EXHIBIT 111

Service Date: April 7, 2026

STATE OF WASHINGTON

UTILITIES AND TRANSPORTATION COMMISSION

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April 7, 2026

NOTICE OF HYBRID TECHNICAL CONFERENCE
(set for Monday, April 27, 2026, at 9 a.m.)

Phone: (253) 215-8782 • Meeting ID: 850 3551 0092# • Passcode: 075676#
Zoom: Click here to join meeting[1]

TO ALL INTERESTED PERSONS

The Washington Utilities and Transportation Commission (Commission or UTC) has opened Docket UE-260162 to proactively explore the effects of emerging large loads on electric utilities. Investor-owned utilities regulated by the Commission have not yet brought on significant large load customers in their service territories. However, consistent with the UTC's mission to protect the people of Washington by making sure investor-owned utility services are safe, equitable, available, reliable, and fairly priced, the Commission will use this docket to prepare for any future large load customers in electric service territories regulated by the Commission.

Large load customers pose unique risks and opportunities for the traditional business models and regulatory environments of electric utilities, especially in the constrained power system of the Pacific Northwest. In this docket, the Commission will focus on developing principles and policies related to large loads seeking service from and interconnection with investor-owned electric utilities (electric IOUs) subject to the Commission's jurisdiction.

Through Docket UE-260162, the Commission plans to engage interested persons to identify key issues related to the interconnection of large load customers with electric IOUs. The Commission will convene at least one technical conference, followed by additional technical conferences and workshops as needed. The Commissioners will not attend the technical conferences, but will be present at the workshops. The Commission will offer ample opportunities for written comment throughout the process. Ultimately, the Commission plans to release a policy statement that offers principles and policies regarding large load interconnection with electric IOUs, including guidance for ratepayer protections and risk mitigation.

[1] https://utc-wa-gov.zoom.us/j/85035510092?pwd=tdaz1rYovufx8LFL0aRAiHan6if6KN.1.

There are significant emerging impacts and effects of large loads on public infrastructure including but not limited to water availability, waste generation, air permitting, tax incentives, and cybersecurity. This docket will not cover the effects of large loads that are not directly related to electric IOU operations. The Commission acknowledges that large loads create other effects on public infrastructure but recognizes that these issues are largely outside of the Commission's jurisdiction. Although water rates for regulated companies do fall under Commission jurisdiction, the Commission declines to address water usage in this docket. Should it become necessary to address the issue of water usage the Commission will either expand the scope of this docket or create a new docket.

BACKGROUND

Large load interconnections and demand for electricity are rapidly growing across the United States and the Western Interconnection. This growth is fueled in part by large loads, which include data centers, manufacturing facilities, hydrogen production, as well as aggregate loads from heating, cooling, and electrification, including EV charging.[2]

In 2025, Washington Governor Bob Ferguson issued Executive Order 25-05, which created the Data Center Workgroup (DCWG). UTC Chair Rybarik participated in the DCWG as the representative of the Commission. In the preliminary report published by the Department of Revenue, the DCWG specifically recommends that the Commission work to strengthen ratepayer protections and improve resource forecasting with respect to new large loads. The DCWG also recommended that state agencies incentivize flexibility and energy efficiency while accelerating the siting and permitting of clean energy generators and transmission.[3] The legislature contemplated regulation of "emerging large energy use facilities" during the 2025-2026 legislative session, including HB 2515, which ultimately did not pass.[4]

The Commission believes that it has sufficient jurisdiction to examine these issues concerning electric IOUs through a policy docket. Under Revised Code of Washington (RCW) 34.05.230(1), agencies are "encouraged to advise the public of its current opinions, approaches, and likely courses of action by means of interpretive or policy statements."

NOTICE OF TECHNICAL CONFERENCE

The Commission will convene a hybrid technical conference on April 27, 2026, beginning at 9:00 AM. The Commissioners will not be in attendance, and the conference will be recorded. The recording will be shared in the docket following the conference.

The Commission will hold the conference in-person with the option to participate virtually. Commission headquarters will be open to the public for in-person participation. Interested

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[2] Western Electricity Coordinating Council (WECC), *An Assessment of Large Load Interconnection Risks in the Western Interconnection*, Page 5.

[3] Washington State Department of Revenue, *Data Center Workgroup: Preliminary Report*.

[4] HB 2515, Washington State Legislature

persons may listen to the meeting via Zoom by calling (253) 215-8782 and using Meeting ID 850 3551 0092# and the Passcode 075676#. To participate in the meeting using Zoom on a computer or mobile device, click here to join the conference.[5] If you wish to be placed on the interested parties contact list, please submit your request to the Commission's Records Center at records@utc.wa.gov.

QUESTIONS FOR WRITTEN COMMENT

The Commission asks that interested persons submit written comments in response to the following questions by April 21, 2026, at 5 p.m. for the technical conference on April 27, 2026. Comments submitted after April 21, 2026, will be considered but may not be included in the presentation slides. Answers to these questions and the discussion at the technical conference will be used to inform the future direction for engagement in this docket.

At this technical conference, the Commission would like to clarify technical details related to the relationship between large loads and electric IOUs including the definition of a "large load." Some of the questions relate to how the electric IOUs and the Commission will track and share information on large loads.

In general, the Commission poses these questions to set the stage for future discussions in this docket. Space will be left at the end of the technical conference agenda for staff and participants to explore other concerns related to large loads. Future topics for this docket will be informed by the comments submitted and the conversations shared at this technical conference.

1. How should the Commission and electric IOUs define "large loads?" Should it be based on a specific MW threshold, characteristics of the load itself, end use, current utility definitions, or a combination of those criteria?[6]

2. When large loads interconnect to a utility system, there are usually resulting costs to accomplish the interconnection. These costs can be direct, such as generation required to serve load or site-specific transmission upgrades, and indirect, such as increased demand for resources in the broader power market or other supply chain and resource adequacy constraints.[7]

    a. What are particular costs (or benefits) related to large loads that the Commission and electric IOUs should quantify and track?

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[5] https://utc-wa-gov.zoom.us/j/85035510092?pwd=tdaz1rYovufx8LFL0aRAiHan6if6KN.1.

[6] HB 2515 defined "emerging large energy use facilities as being over 20 MW and listed under 518210 of North American Industry Classification System (NAICS). The federal Northwest Power Act defines "New Large Single Loads" as one that results in an increase in power requirements of ten average MW or more in any 12-month period. The DCWG did not define large loads but recommends that the Commission and Commerce identify a MW threshold for large loads and specify their characteristics.

[7] 2025 Large Load Literature Review | Energy Markets & Planning, 2026 Large Load Literature Review and Data Sources | Energy Markets & Planning

b. Would tracking the costs related to large loads require different approaches than the Commission's and electric IOU's existing practices?

3. What data do the Commission, electric IOUs, and interested persons require to assess the effects of large loads in an IOU service territory? Is that data publicly accessible or otherwise available through existing UTC processes? Are there third-party sources of data that could be used when assessing large loads in a utility setting?

    a. In line with the DCWG recommendations, what data is needed to incentivize greater demand flexibility and energy efficiency that allows for interconnection of new large loads?[8]

4. Industry expertise suggests that more uniform forecasting frameworks and modeling methodologies are needed to accurately forecast large loads and protect customers from risk.[9]
    a. How should electric IOUs evaluate requests for interconnection from large load customers?
    b. How should electric IOUs forecast large load demand within their service territories, or otherwise consider large load demand in their forecasts and planning processes?
    c. Are current electric IOU practices related to resource adequacy metrics sufficient for large loads? Why or why not?[10]
    d. What steps should be taken by electric IOUs or the Commission to manage changing conditions for the arrival, departure, or overall demand of a large load?

5. What mechanisms, in WA or elsewhere, could be used to protect ratepayers from bearing additional cost burden from large load interconnections and operations?

In addition to the questions for interested persons, the Commission has specific questions on current utility processes. While we mainly seek answers related to these current practices from utilities, we also seek feedback from other interested persons on what utilities should do related to these practices.

1. What is your company's current process for large load interconnections? What existing industry research and literature does your company use to guide its interconnection process?

2. How many requests for large load customers are currently in your company's interconnection queue?

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[8] Washington State Department of Revenue, *Data Center Workgroup: Preliminary Report*, page 22.

[9] Forecasting Large Loads in the Age of AI and Data Centers - E3, Large Load Modeling for Dynamic Studies: Current Practices and Recommendations | ESIG.

[10] WAC 480-100-620 says that an integrated resource plan must include an assessment and determination of resource adequacy metrics. It must also identify an appropriate resource adequacy requirement and measurement metrics consistent with RCW 19.405.030 through 19.405.050.

3. What tariff schedules currently serve large load customers? Does your company currently have any special contracts with large load customers? If so, please identify these contracts.

4. How does your company currently consider large loads in load forecasting and integrated resource planning practices? What existing industry research and literature does your company use to guide its forecasting process?[11]

Information related to this proceeding, including comments filed by interested persons, will be posted on the Commission's website as it becomes available. Persons filing comments will receive future communications the Commission issues in this docket. If you do not file comments but wish to receive such information you may contact the Commission's Records Center by telephone at (360) 664-1234 or by email at records@utc.wa.gov and ask to be including on the mailing list for Docket UE-260162.

If you have any questions regarding this docket, you may contact Charlie Inman, Energy Policy Advisor, by email at charlie.inman@utc.wa.gov.

JEFF KILLIP
Executive Director and Secretary

[11] Examples include Forecasting Large Loads in the Age of AI and Data Centers - E3, Large Load Modeling for Dynamic Studies: Current Practices and Recommendations | ESIG.

EXHIBIT 112

Statement on NERC's 2024 Long-Term Reliability Assessment

June 25, 2025 Headlines

WASHINGTON, D.C. — Recent comments by MISO's Independent Market Monitor at the Federal Energy Regulatory Commission's Reliability Technical Conference on resource adequacy asserted certain data discrepancies in the MISO area in NERC's *2024 Long-Term Reliability Assessment,* which resulted in the understatement of resource availability. Following an in-depth review, NERC found that MISO submitted mismatched data, which overstated the near-term energy shortfall risk. When reanalyzed with the corrected data, the MISO footprint was reclassified as an "elevated risk" over the next few years, shifting to "high risk" in the 2028–2031 timeframe, depending on new resource additions/retirements. Elevated risk areas meet resource adequacy criteria; however, under extreme weather conditions these areas are likely to experience a shortfall in reserves. There was no impact on the recently released *2025 Summer Reliability Assessment,* which analyzes different data.

While this data mismatch went unnoticed by MISO and the Midwest Reliability Organization (MRO) that initially collects and vets the data, NERC is ultimately responsible for ensuring the accuracy of its independent reliability assessments and is working to improve its review process. Currently, the control process calls for extensive checks by submitting entities and the Regional Entities as well as peer review by the Reliability Assessment Subcommittee. Going forward, NERC, MRO and MISO are all committed to improving the data validation process to ensure accuracy. A corrected version of the *2024 LTRA* will be posted soon.

NERC is proud of its independent, continent-wide reliability assessments and regrets this discrepancy. We are pleased that our reports help focus the national discussion on reliability. NERC is committed to ensuring its independent assessments provide accurate, actionable information to industry, policymakers and our U.S. and Canadian stakeholders.

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EXHIBIT 113

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Interconnection of Large Loads to the Interstate Transmission System	**)** **)**	**Docket No. RM26-4-000**

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO NOTICE INVITING COMMENTS

The North American Electric Reliability Corporation ("NERC") submits comments on the Federal Energy Regulatory Commission ("FERC" or "Commission") Notice Inviting Comments[1] regarding the proposed Advance Notice of Proposed Rulemaking ("ANOPR"), *Ensuring the Timely and Orderly Interconnection of Large Loads*.[2] Issued pursuant to the Department of Energy ("DOE") Secretary's authority under section 403 of the DOE Organization Act[3] for Commission consideration and final action, the proposed ANOPR directs the Commission to initiate rulemaking procedures on potential reforms to enable the interconnection of large loads to the transmission system.

As described in these comments, NERC supports the Commission's consideration of how best to ensure the Bulk Power System ("BPS") meets the needs of growing demand from large loads. In addition, NERC appreciates the Secretary's recognition of NERC's role in reliably advancing the integration of these large loads. NERC's mission to assure the effective and efficient reduction of risks to the reliability and security of the BPS aligns with the Secretary's objective to support quick and reliable interconnection of the growing large load population. Through the lens of risk mitigation, NERC Reliability Standards are an important part of ensuring that the BPS is

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1 *Interconnection of Large Loads to the Interstate Transmission System*, *Notice Inviting Comments,* Docket No. RM26-4-000 (Oct. 27, 2025).

2 *Ensuring the Timely and Orderly Interconnection of Large Loads*, *Advance Notice of Proposed Rulemaking,* Docket No. RM26-4-000 (Oct. 27, 2025) [hereinafter ANOPR].

3 42 U.S.C. § 7173(a).

ready to meet the needs of a North American economy that is heavily reliant on the electric grid. Accordingly, NERC requests that any ensuing Commission action accurately reflects the scope of NERC's reliability authority, which statutorily extends to Reliability Standards that provide for the reliable operation of the BPS and is distinguished from the Commission's jurisdiction regarding the transmission and sale of electric energy.[4] While NERC is commenting on its own authority under section 215 of the Federal Power Act, NERC declines to comment on matters outside its purview, such as the proposed ANOPR assertions regarding the Commission's jurisdiction under other provisions of the Federal Power Act, including section 205. Finally, NERC outlines its activities already underway under the NERC Large Loads Action Plan to address the urgent need to properly manage the risks associated with growing demand from large load users of the BPS while also enabling them to interconnect quickly and participate in NERC stakeholder activities.

These comments are organized as follows: Section I describes how NERC's background and mission can help support the Secretary's goal of interconnecting large loads quickly and reliably; and Section II describes NERC's authority and the high priority work that NERC is currently undertaking to help support the reliable integration of large loads. NERC respectfully requests the Commission consider these comments in determining any final action in response to the proposed ANOPR.

I. BACKGROUND ON NERC

As the Commission-certified Electric Reliability Organization ("ERO"), NERC's mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

[4] The Federal Power Act states that the jurisdiction of the Commission for the purpose of certain sections of the act, including section 215 regarding reliability, is provided in the specific provisions of those sections. *See* 16 U.S.C. § 824(b)(1) and (2).

When Congress enacted the Energy Policy Act of 2005[5] and section 215 of the Federal Power Act ("section 215"),[6] it entrusted the Commission with: (i) approving and enforcing rules to ensure the reliability of the BPS;[7] and (ii) certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval, and assessing reliability and adequacy of the BPS in North America.[8] In 2006, the Commission certified NERC as the ERO pursuant to section 215.[9]

To effectively and efficiently reduce risks to reliability, NERC develops and enforces Reliability Standards to ensure an adequate level of reliability of the BPS. NERC executes its mission through delegation of certain activities to six Regional Entities.[10] Reliability Standard obligations apply to entities registered with NERC pursuant to the registration process and registry criteria included in the NERC Rules of Procedure.[11] NERC and the Regional Entities have the obligation to identify and register all entities that meet the criteria for inclusion in the NERC

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5 Energy Policy Act of 2005, Pub. L. 109–58, §1211(b), 119 Stat. 941-46 (2005).

6 16 U.S.C. § 824o [hereafter section 215].

7 The NERC Rules of Procedure Appendix 2 state the "Bulk Power System" means, depending on the context:

(i) (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy [++]. (Note that the terms "Bulk-Power System" or "Bulk Power System" shall have the same meaning.)

(ii) Solely for purposes of Appendix 4E, Bulk Electric System.

Part (i) of this definition is taken from Section 215 of the Federal Power Act, 16 U.S.C. § 824o(a)(l). The NERC Rules of Procedure are available at https://www.nerc.com/who-we-are/rules-of-procedure.

8 Section 215(a)(2). *See also* Section 215(c) (providing the ERO certification criteria). *See also* Energy Policy Act of 2005, Pub. L. 109–58, §1211(b), 119 Stat. 941, 946 (2005), (clarifying, "[t]he Electric Reliability Organization… and any regional entity delegated enforcement authority… are not departments, agencies, or instrumentalities of the United States Government.").

9 *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006).

10 The six Regional Entities include the following: Midwest Reliability Organization, Northeast Power Coordinating Council, Inc., ReliabilityFirst Corporation, SERC Reliability Corporation, Texas Reliability Entity, Inc., and Western Electricity Coordinating Council

11 *See* NERC Rules of Procedure at Section 500 and Appendices 5A and 5B.

Compliance Registry ("NCR").[12] Once registered, such entities are subject to Commission-approved Reliability Standards.

NERC Reliability Standards operate in partnership with the Commission's interconnection procedures and agreements. NERC's suite of Reliability Standards includes requirements intended to address potential risks associated with interconnecting resources. For example, Reliability Standard FAC-001-4[13] requires responsible entities to document and make facility interconnection requirements available so that interconnecting entities provide the necessary information to ensure their reliable interconnection. In addition, Reliability Standard FAC-002-4 requires responsible entities to study the impact of interconnecting new or changed facilities on their portion of the system.[14] These Reliability Standards requirements supplement the interconnection requirements and help to ensure that entities appropriately account for the impact of interconnecting facilities to the BPS.

Similarly, the Commission's interconnection procedures and agreements are complementary to the NERC Reliability Standards. The Commission interconnection procedures and agreements provide uniformity for both transmission providers and interconnection customers. These procedures also help prevent undue discrimination and preserve reliability.[15] Moreover, the Commission's procedures have the advantage that they may apply to interconnecting entities prior to operation. Thus, such obligations may apply prior to an entity's registration on the NCR. As a

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[12] The NCR identifies the owners, operators, and users of the BPS that are responsible for complying with approved reliability standards applicable to the functions for which each entity is registered.

[13] Available https://www.nerc.com/standards/reliability-standards/fac/fac-001-4.

[14] Available https://www.nerc.com/standards/reliability-standards/fac/fac-002-4.

[15] *See* Order Nos. 2003 and 2006 (regarding large and small generators, respectively). *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC 61,103 (2003); *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, 111 FERC 61,220 (2005).

result, the Commission's interconnection procedures and agreements provide an important first line of defense to protect against potential risks to the BPS as new resources interconnect.

II. COMMENTS

NERC submits the following comments on the proposed ANOPR for the Commission's consideration. Section A expresses NERC's support for the Commission addressing the rapid growth of large loads and NERC's appreciation for the Secretary's acknowledgment that NERC Reliability Standards requirements play an important role in ensuring the BPS can meet the needs of large loads. Section B requests that any Commission action resulting from the proposed ANOPR reflects NERC's authority as the ERO under the Federal Power Act section 215. Finally, Section C describes NERC activity under the Large Loads Action Plan to address the impacts of large loads on the BPS and describes stakeholder involvement.

A. NERC supports the Commission addressing the rapid growth of large loads and appreciates the Secretary's recognition of NERC's role in ensuring the Bulk Power System can reliably advance the United States' economy and innovation.

NERC welcomes the opportunity to timely address a unique and growing population of users of the BPS. As cited by the ANOPR, the NERC 2024 Long-Term Reliability Assessment ("NERC 2024 LTRA") identified that demand growth is higher than at any point in the last two decades.[16] The NERC 2024 LTRA also notes that "[d]emand and energy growth projections in this assessment period provide both challenges and opportunities for electric grid reliability."[17] Such unique challenges include demand forecasting and planning for system behavior when some large loads, such as data centers for cryptocurrency mining and artificial intelligence, are substantially

[16] ANOPR at P 1 (citing NERC, *2024 Long- Term Reliability Assessment* (Dec. 2024, updated July 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf at 8). NERC develops the LTRA annually in accordance with the NERC Rules of Procedure and Title 18, § 39.112 of the Code of Federal Regulations; this is also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.

[17] NERC 2024 LTRA at 33.

larger and constructed more quickly than prior large loads using the BPS.[18] NERC recognizes that this environment creates a need for quick and decisive action to address any potential impacts to reliability to support the exponential growth in an economy dependent upon reliable electricity. In addressing these risks, NERC enables loads to connect confidently and reliably to the transmission system, consistent with the Secretary's objectives. Accordingly, based on NERC's assessment of reliability implications of large loads in the NERC 2024 LTRA, NERC initiated further study and collaboration with stakeholders to help ensure a reliable transmission system for all, as further described in Section II.C of these comments.

In addition to supporting the Commission's addressing the rapid growth of large loads, NERC appreciates the Secretary's acknowledgment of NERC's role in reliably advancing the electric grid to meet the needs of the United States' economy.[19] Among the Secretary's proposed principles is a proposal that "utilities serving large loads must meet all applicable NERC reliability standards…."[20] In addition, the proposed ANOPR states, "NERC should review its reliability standards to determine if new registration categories or new or modified reliability standards are required to ensure reliability of the [Bulk Electric System ("BES")]."[21] The proposed principles demonstrate the Secretary's recognition that NERC's mandatory Reliability Standards play an important role in helping to ensure the electric grid can reliably meet the needs of interconnecting large load and other BPS users.

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18 *Id.* at 8.

19 Letter from the Secretary of Energy to FERC, *Re: Secretary of Energy' s Direction that the Federal Energy Regulatory Commission Initiate Rulemaking Procedures and Proposal Regarding the Interconnection of Large Loads Pursuant to the Secretary' s Authority Under Section 403 of the Department of Energy Organization Act* (Oct. 23, 2025), https://www.energy.gov/sites/default/files/2025-10/403%20Large%20Loads%20Letter.pdf (noting that the Administration is committed to revitalizing domestic manufacturing and driving American AI innovation, which requires large quantities of electricity and investment in the Nation's interstate transmission system).

20 ANOPR at P 31.

21 *Id.* The Bulk Electric System is a subset of the broader Bulk Power System.

NERC works to ensure that Reliability Standards, and entities required to comply with them, are limited to those that are material to the reliability of the BPS. NERC develops its suite of standards through a consensus-driven standards development process that is open to all those interested in reliability.[22] Through that process, NERC engages with stakeholders, including those who must comply with Reliability Standards, to determine mandatory requirements that can be tailored and implemented effectively to mitigate specific reliability risks. Should NERC's assessments, collaborative efforts with stakeholders, or standards development process indicate that mandatory requirements are not the appropriate mechanism to mitigate a particular risk, NERC has other tools to effectively address reliability risks. Such tools may include, for example, technical reference documents, Reliability Guidelines, and Alerts.[23] NERC's measured approach efficiently and effectively mitigates risks to reliability and contributes to NERC's successful collaboration with industry stakeholders, governmental authorities, and the public.

B. In determining any Commission action resulting from the proposed ANOPR, the Commission should reference the full scope of NERC's authority as the ERO under Federal Power Act section 215 to ensure the reliable operation of the BPS.

While NERC Reliability Standards focus on a curated set of actors and actions that mitigate risk, NERC's authority as the ERO under the Federal Power Act section 215[24] could extend more broadly than its current exercise of that reliability jurisdiction. NERC appreciates that the proposed

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[22] NERC's Reliability Standards development process is including in its Rules of Procedure, Appendix 3A (Standard Processes Manual), available at https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/appendix_3a_spm_clean_mar2019.pdf. While NERC is currently developing recommendations for further streamlining of its standard development process, the current recommendations still emphasize consensus-building at key points in the process. The proposed recommendations are available at https://www.nerc.com/globalassets/initiatives/modernization-of-standards-processes-and-procedures-task-force-mspp/draft-recommendations---october-2025.pdf.

[23] As an example, NERC issued an Alert regarding an industry recommendation to address the risks observed from the analyzed large load behavior and to assess the status of industry preparedness in relation to large loads. The Alert is available at https://www.nerc.com/globalassets/programs/bpsa/alerts/2025/nerc-alert-level-2--large-loads.pdf.

[24] Section 215.

ANOPR recognizes that NERC's reliability authority statutorily applies to the Bulk Power System.[25] However, there is opportunity to further clarify NERC's authority as the ERO under section 215, because one of the proposed ANOPR principles suggest that NERC's registration categories and Reliability Standards are to ensure the "reliability of the BES."[26] As such, NERC requests out of an abundance of caution that any subsequent Commission action in this proceeding reflects the full scope of NERC's reliability authority as pertaining to the BPS. Within that scope, NERC seeks to exercise its authority to address risks to the reliability of the BPS, and in addressing those risks, NERC can help facilitate loads interconnecting reliably. As NERC's reliability authority under section 215 is distinct from Commission jurisdiction on the sale and transmission of electric energy under Federal Power Act section 201(b)(1), NERC declines to comment on other jurisdictional principles raised in the proposed ANOPR.[27] Nevertheless, while NERC is focused on how to support the integration of large load with the BPS consistent with the scope of its section 215 authority, NERC looks forward to continued coordination between State and Federal entities in this area.

Under section 215, the Federal Power Act provides the Commission, via the ERO, authority to regulate "users, owners, and operators of the Bulk Power System (BPS)."[28] This statutory authority to regulate includes: (1) developing and enforcing mandatory Reliability

25 ANOPR at P 1 n.2.

26 *Id*. at P 31.

27 *Supra* note 4.

28 Section 215(b).

Standards[29] that provide for reliable operation[30] of the BPS, subject to approval by FERC; and (2) assessing BPS reliability and adequacy.[31] Consistent with federal jurisdiction over interstate commerce and other sections of the Federal Power Act, Congressional authority under section 215 pertains only to the BPS and "users, owners, and operators" of the BPS. As such, under section 215, NERC cannot: (1) develop and enforce Reliability Standards for reliable operation of facilities used in the local distribution of electric energy, or (2) order the construction of additional generation or transmission capacity or set and enforce compliance with standards for adequacy or safety of electric facilities or services.[32] While the Federal Power Act defines the parameters of the BPS, it does not define the terms "users", "owners", or "operators" of the BPS.

FERC's regulations echo Federal Power Act section 215 by requiring that "each user, owner and operator of the [BPS] within the United States…shall register with the [ERO] and the Regional Entity for each region within which it uses, owns, or operates [BPS] facilities, in such manner as prescribed by the Rules of the [ERO] and each applicable Regional Entity."[33] As with the Federal Power Act, FERC's regulations do not further define the terms "users", "owners", or "operators" of the BPS, leaving it to NERC and the Regional Entities to identify those entities through their rules, such as the NERC registry criteria.[34]

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[29] Section 215 defines "Reliability Standard" as "a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity." *See* 16 U.S.C. 824o(a)(3).

[30] Section 215 defines "reliable operation" as "operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements." *See* 16 U.S.C. 824o(a)(4).

[31] Section 215.

[32] Section 215 (a)(1) and (i).

[33] 18 C.F.R. § 39.2(c).

[34] NERC's current registry criteria are listed in Appendix 5B of the NERC Rules of Procedure, available at https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/appendix-5b-eff-20240627_signed.pdf.

Specifically, the NERC registry criteria identify the subset of owners, operators, and users who have a material impact on the BPS and must therefore comply with applicable Reliability Standards. Currently, the registry criteria include entities that use, own, or operate BES Elements[35] as well as those entities otherwise defined by the registry criteria as materially impacting BPS reliability. While a majority of criteria pertain to the BES, which is a subset of the BPS, the registry criteria do include some applicable to certain non-BES resources. The registry criteria could be expanded to include additional owners, operators, or users of the BPS to the extent that the entities might materially impact reliability of the BPS.

While owners and operators of the BPS are well-defined through NERC's registry criteria, NERC currently has limited registry criteria applicable to "users" of the BPS. Nevertheless, FERC precedent and legislative history of the Federal Power Act indicate that users of the BPS mean all those who "use" the BPS. For instance, in rejecting NERC's attempts to define "user" of the BPS, FERC stated its concerns that, "[under NERC's proposed definition] a large industrial customer that receives electric energy directly from the [BPS] may not be defined as a user of the BPS, even though it may directly affect the reliability of the [BPS]."[36] As such, FERC contemplated that a user of the BPS could be a large industrial customer receiving electric energy directly from the BPS.[37] Similarly, when the Commission reviewed the initial suite of NERC Reliability Standards, it further declined to define user of the BPS, stating:

> While we recognize the desire of some commenters for a concise, generic definition of "user of the Bulk-Power System," we are concerned that any

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[35] The BES is defined in NERC Rules of Procedure Appendix 2, https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/appendix-2-eff-20240627_signed.pdf, and in the *Glossary of Terms Used in NERC Reliability Standards*, https://www.nerc.com/globalassets/standards/reliability-standards/glossary_of_terms.pdf [hereinafter Glossary].

[36] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC 61,104 at P 99 (2006) [hereinafter Order No. 672], *order on reh'g*, Order No. 672-A, 114 FERC 61,328 (2006).

[37] *Id.* at PP 98-99.

> attempt to define the term at this time will either be overly broad so as not to provide any helpful guidance or overly narrow so as to exclude entities that should be covered. The Commission believes that it has employed a reasonable approach by endorsing NERC's compliance registry process and requiring that each Reliability Standard identify the subset of users, owners and operators to whom that particular Reliability Standard applies.[38]

Accordingly, while there is no definition of "user" of the BPS or current registry criteria for users, the Commission has previously considered what it means to be a "user" of the BPS.

Legislative history of the Federal Power Act provides further insight into the intent of "user" of the BPS. During debate on the amendment that incorporated user of the BPS into the Federal Power Act, the author of the amendment, Senator Thomas, explained that "[t]he new reliability organization will have enforcement powers, with real teeth to ensure reliability. The amendment provides that mandatory reliability rules will apply to all users of the transmission grid. There are no loopholes. No one will be exempt."[39] Senator Bingaman, who while opposing the Thomas Amendment was a proponent of a mandatory system of reliability rules, recognized that "[t]he reliability system needs to apply to all users. The rules need to be enforceable. There need to be penalties if you do not comply with the rules."[40]

While NERC's reliability authority extends to all users, owners, and operators of the BPS, NERC's registry criteria and Reliability Standards identify the appropriate users, owners, and operators based on an exercise of reasonable judgment as to their potential material impact to the

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[38] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 118 FERC ¶ 61,218 at P 116, (2007) [hereinafter Order No. 693], *order on reh'g*, Order No. 693-A, 120 FERC 61,053 (2007).

[39] 148 Cong. S1874 (daily ed. Mar. 14, 2002) (statement of Sen. Thomas).

[40] *Id.* (statement of Sen. Bingaman). NERC originally highlighted this legislative history in a notice of penalty proceeding. See NERC, *Notice of Penalty regarding U.S. Army Corps of Engineers – Tulsa District,* Docket No. NP09-26-000 at 6 (June 24, 2009). In issuing a determination on NERC's jurisdiction under section 215 in that penalty proceeding, the Commission concluded that Congress intended section 215 to be comprehensive and was added to prevent cascading blackouts, as demonstrated by the provisions of the Federal Power Act and its legislative history. See *Order Addressing Applicability of Section 215 of the Federal Power Act to Federal Entities*, 129 FERC ¶ 61,033 (2009), *reh'g denied*, *order rejecting reh'g request*, 130 FERC ¶ 61,002 (2010).

BPS. NERC applies risk-based engineering judgment to assess the impact of a particular user, owner, or operator on the BPS and whether any action(s) taken by that user, owner, or operator could mitigate risks posed by that impact. This risk-based analysis is used to support any registry criteria in the Rules of Procedure. Not only does NERC reasonably exercise its authority through this assessment, but it also invites stakeholders, including those who could be subject to Reliability Standards, to participate in determining the appropriate action. As more fully described in Section II.C. below, NERC's review of its registry criteria and Reliability Standards provides ample opportunities for participation, consistent with the principles in the proposed ANOPR.

Although NERC has not developed any criteria that would add large load entities to the NCR at this time, NERC requests that any resulting Commission action reflect NERC's scope of statutory authority as the ERO to ensure the reliability of the BPS. While NERC currently relies on the BES as a proxy for whether an asset is used in local distribution or not, NERC's authority to regulate reliability extends to users, owners, and operators, as needed, to ensure the reliability of the BPS.[41] NERC's request of the Commission should not be construed to mean that NERC will develop regulations to the full extent of its statutory authority. Rather, the request reflects that any risk assessment of impacts to the BPS needs to factor in any users, owners, or operators of the BPS and their material impact on the reliability of the BPS. NERC plans to coordinate with stakeholders over the following year to explore potential revisions to the registry criteria and Reliability Standards that would incorporate large loads impacting the reliable operation of the BPS. An example timeline of such potential activities is provided in Section II.C of these comments.

[41] As an example, NERC recently revised its registry criteria to include certain inverter-based resources that are not included in the BES. NERC justified such addition based on the resources' aggregate material impact to the BPS. *See Order Approving Revisions to North American Electric Reliability Corporation Rules of Procedure and Requiring Compliance Filing*, 187 FERC ¶ 61,196 (2024) (approving revisions to the NERC registry criteria to include certain owners and operators of inverter-based resources that are connected to the BPS but that were previously not otherwise required to register with NERC under the BES definition).

C. NERC has already initiated extensive collaboration with industry through the Large Loads Action Plan and continues to invite all stakeholders to participate.

As the Secretary noted in the letter accompanying the proposed ANOPR sent to the Commission, this is an urgent issue that requires prompt attention. NERC agrees and has met such urgency with action – specifically, the Large Loads Action Plan.[42] As described in this section, the Large Loads Action Plan builds off the work of the NERC Reliability and Security Technical Committee's ("RSTC") Large Loads Task Force ("LLTF"), established in August 2024 to assess the impacts of large load on the BPS. Through these efforts, NERC is conducting activities that support a review of its Reliability Standards to determine if new registration categories or revisions to the Reliability Standards are required to ensure reliability of the BPS, consistent with the principles in the proposed ANOPR.

Since March of 2024, NERC and the Regional Entities have been examining how large loads can be reliably integrated with the North American BPS. Over the past year, the LLTF has codified its assessment of reliability risks that large loads may pose to the BPS through development of white papers. The LLTF white paper *"Characteristics and Risks of Emerging Large Loads"* ("White paper 1"), for example, characterizes large loads and defines the reliability risks that they may pose to the BPS.[43] One such risk includes the potential for large amounts of voltage-sensitive load loss, which NERC evaluated after a 2024 disturbance.[44]

Based on NERC assessments and the work of the LLTF, addressing large loads has become a priority for NERC's leadership. NERC's Member Representatives Committee provided written

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[42] The NERC Large Loads Action Plan and related information is available at https://www.nerc.com/initiatives/large-loads-action-plan.

[43] NERC, *Characteristics and Risks of Emerging Large Loads: Large Loads Task Force White Paper* (July 2025), https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf.

[44] NERC, *Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions* (Jan. 2025), https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_large_load_loss.pdf.

input and hosted a technical panel session on large loads at the February 2025 NERC Board of Trustees ("Board") meeting. In addition, the Board issued a resolution in February 2025 directing NERC to develop an action plan, which complements the work of the LLTF and provides additional structure to NERC's efforts related to large loads integration. Under the Large Loads Action Plan, NERC has conducted several workshops with industry and large load users of the BPS, prepared technical reference material, and shared guidance on how to mitigate potential risks to reliability. Moreover, the Large Loads Action Plan includes an action item on registration analysis, which analyzes the legal basis for registration of large users of the BPS and whether there are Reliability Standards requirements that could apply to such users. In addition, the Large Loads Action Plan includes analysis on whether any revisions to the Reliability Standards for existing entities on the NCR could mitigate impacts to BPS reliability.

In the first quarter of 2026, NERC will develop additional findings, guidance, and next steps to account for the BPS reliability needs associated with large loads. First, on January 28, 2026, responsible entities are expected to respond to the Level 2 Alert *Industry Recommendation Large Load Interconnection, Study, Commissioning, and Operations* ("Level 2 Alert").[45] The purpose of the Level 2 Alert is to address the risks observed from analyzed large load behavior and to assess the status of industry preparedness in relation to large loads. By February 27, 2026, NERC will submit a report to the Commission regarding responses to the Level 2 Alert. NERC will post a public version of the report thereafter. NERC is also collecting comments on a draft LLTF *Reliability Guideline: Risk Mitigation for Emerging Large Loads* ("LLTF Reliability

[45] NERC, *Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations* (Sep. 9, 2025), https://www.nerc.com/globalassets/programs/bpsa/alerts/2025/nerc-alert-level-2--large-loads.pdf.

Guideline").[46] In addition, by the first quarter of 2026, the LLTF plans to finalize a whitepaper on the existing practices, requirements, and Reliability Standards for emerging loads ("White paper 2").

Through these upcoming work products, NERC aims to identify immediate, short-term, and longer-term measures to support the integration of large loads with the BPS and mitigate any identified risks to reliability. The Level 2 Alert, White paper 2, and draft LLTF Reliability Guideline will provide practical recommendations, such as better data collection and validation. Depending on the outcome of these activities, next steps may include NERC registry criteria updates that help mitigate risk associated with emerging large loads. As discussed at the Commission-led 2025 Reliability Technical Conference,[47] any updates to registry criteria would be dependent upon whether relevant users, owners, and operators of the BPS could materially impact, either individually or in aggregate, the reliability of the BPS.

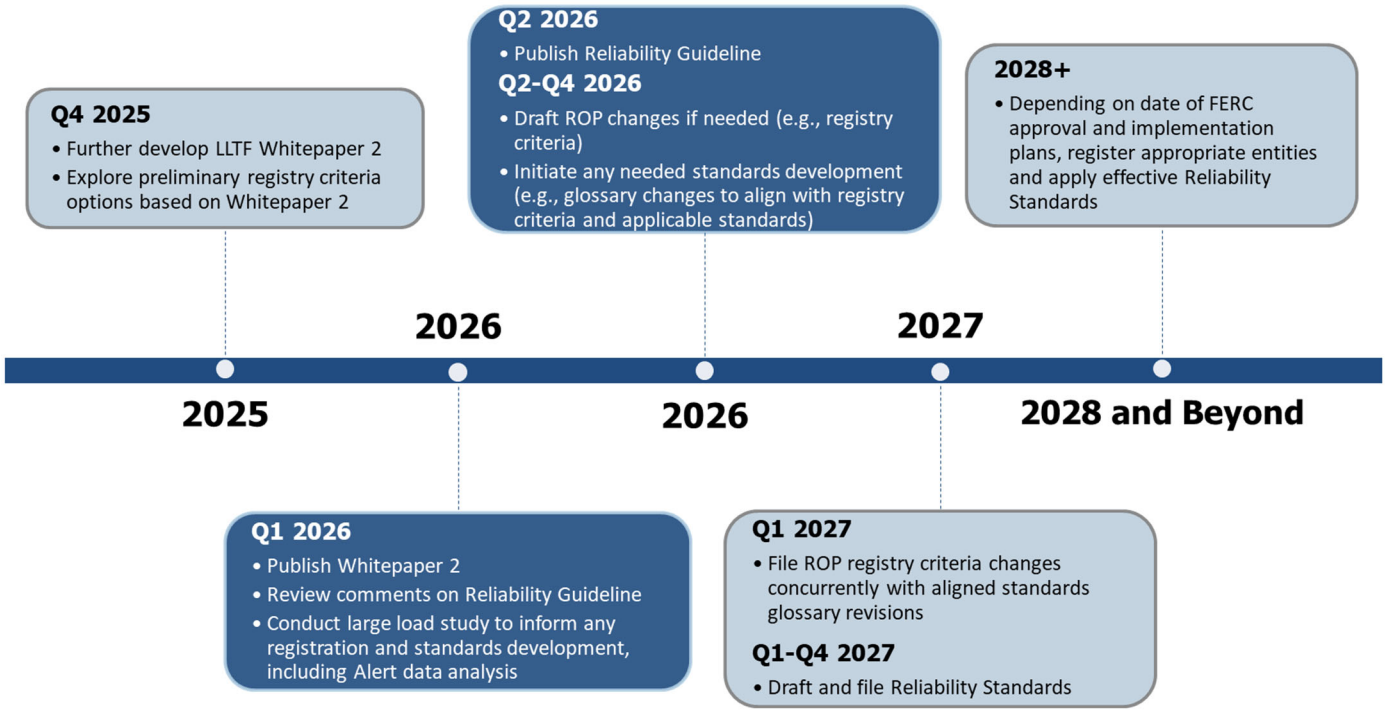
Stakeholder engagement is a key component of NERC's Large Loads Action Plan, consistent with NERC's participatory culture. As an illustration of stakeholder involvement under the Large Loads Action Plan, each LLTF whitepaper has generated hundreds of comments across industry. Hundreds of industry stakeholders, including large load users of the BPS, have attended NERC's technical workshops on large loads. Moreover, while the large end-use sector has been open to participants under NERC's stakeholder process, NERC's External Affairs team as well as NERC engineering staff have conducted significant efforts to bring large load users into

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[46] This is a Reliability Guideline identifying risk mitigation including improvements to existing planning, and operation processes and interconnection requirements for large loads. Guidance may include recommended improvements to modeling practices, analyses, coordination and data collection efforts, real time monitoring and event analysis. *See* NERC, *Preliminary DRAFT Reliability Guideline: Risk Mitigation for Emerging Large Loads*, https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/draft_reliabilityguideline_riskmitigationforemerginglargeloads.pdf.

[47] FERC, *2025 Commissioner-Led Reliability Technical Conference: Annual Reliability Technical Conference, Docket No. AD25-8-000*, https://www.ferc.gov/news-events/events/commissioner-led-reliability-technical-conference-05142025.

stakeholder discussions on large load-related issues over the past two years. NERC will leverage these networks as it examines modifications to its Reliability Standards and registry criteria to accommodate the reliability needs associated with large load. As this has been identified as an urgent issue both by the Secretary and NERC, NERC provides the following example of a timeline for how NERC may address these issues promptly and with the necessary collaboration. As this is an example timeline, it could be subject to change. For instance, should NERC determine the need to develop any new registry criteria, NERC may need additional time to identify entities that may be entirely new to reliability regulations. While not included in the timeline below, NERC continuously informs its Board on these activities and involves stakeholders to help ensure appropriate guidance and perspectives on each step:



Within the above example timeline, stakeholders, including existing and those new to reliability matters, have ample opportunity to participate and directly impact any outcomes,

including changes to registry criteria or Reliability Standards. Specifically, the process for revising the registry criteria within the Rules of Procedure requires a public comment period.[48] The Board considers input from stakeholders in any action to approve the changes. For Reliability Standards development, including revisions to the NERC Glossary, stakeholders can be involved in drafting the Reliability Standards requirements or joining the Registered Ballot Body to vote on or comment on the draft requirements prior to any Board adoption or Commission approval. Each of these steps in the timeline represents meaningful opportunities for the public to provide direct input on the ways NERC could address risk to the BPS from the integration of large loads.

III. CONCLUSION

In conclusion, NERC requests the Commission consider NERC's comments in any ensuing issuances or actions under this rulemaking proceeding. NERC seeks to reinforce its commitment to identifying and mitigating risks to the BPS so that the grid continues to support the North American economy and innovation. NERC looks forward to reviewing other comments submitted in this docket and to partnering with the Commission, other Federal and State entities, industry stakeholders, large load users, and the public to ensure the reliable operation of the BPS.

Respectfully submitted,

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[48] *See* ROP Section 1400 and NERC's Bylaws Article XI, https://www.nerc.com/globalassets/who-we-are/board-of-trustees/nerc_bylaws_board_effective_december_5_2024.pdf.

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Counsel for the North American Electric Reliability Corporation

Date: November 21, 2025

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in the above-referenced proceeding.

Dated at Washington, D.C. this 21st day of November, 2025.

/s/ Marisa Hecht

Marisa Hecht
Counsel for North American Electric Reliability Corporation

EXHIBIT 114-1

IN THE UNITED STATES DISTRICT COURT

FOR THE DISTRICT OF OREGON

NATIONAL WILDLIFE FEDERATION, *et al.*,

Plaintiffs,

and

STATE OF OREGON, *et al.*,

Intervenor-Plaintiffs,

v.

NATIONAL MARINE FISHERIES SERVICE, *et al.*,

Defendants,

and

PUBLIC POWER COUNCIL, *et al.*,

Intervenor-Defendants.

Case No. 3:01-cv-640-SI

AMENDED PRELIMINARY INJUNCTION ORDER[1]

Michael H. Simon, District Judge.

[1] As explained in the concurrently filed Amended Opinion and Order, the Court issues the following Amended Preliminary Injunction Order in response to Plaintiffs' Motion for Clarification, ECF 2669, to address typographical errors and clarify the Court's intent. Federal Defendants either take no position on or do not object to the amendments. ECF 2670 at 2 n.2.

This matter comes before the Court on the motions for preliminary injunctive relief (hereafter, "Motions") filed by Plaintiffs and Intervenor-Plaintiff State of Oregon. The Court has reviewed the filings submitted by all Parties, taken oral argument, and, pursuant to an Opinion and Order filed concurrently herewith, GRANTED the Motions. Accordingly, the Court hereby ORDERS, until this Court orders otherwise, or until such time as the parties agree in writing to amend, supersede, or terminate this Preliminary Injunction:

A. Emergency Protocols, Pre-Coordinated Operations

A. Emergency Protocols. Nothing in this Order shall affect the content or applicability of the Emergency Protocols, Appendix 1 to the 2026 Water Management Plan (Attachment 1 to this Order), which allow modification of the operations ordered herein upon occurrence of specified emergency conditions.

B. Pre-Coordinated Operations and Variances. Nothing in this Order shall prohibit the use of pre-coordinated operations and variances described in section 4 of the 2025 Fish Operations Plan (Attachment 2 to this Order), including as needed to ensure proper functioning of adult fish ladders. Moreover, nothing in this Order shall prohibit application of the short-term adjustments in operating pool elevations pursuant to section 4 of the 2025 Fish Operations Plan for any dam subject to operating pool elevation restrictions under this Order, regardless of whether such dam is listed in that section 4.

B. Fish Passage Spill Operations Injunction

A. Definitions:

1. "125% Gas Cap spill" means spill to the maximum level that meets, but does not exceed, the Total Dissolved Gas ("TDG") criteria allowed under state laws.

2. "FOP" means the U.S. Army Corps of Engineers' ("Corps") annual Fish Operations Plan.

3. "FPP" means the Corps' annual Fish Passage Plan.

4. "FPP spill patterns" means the project-specific spill bay gate openings reflected in the FPP tables.

5. "MIP" means Minimum Irrigation Pool elevation as measured in feet above mean sea level in the reservoir forebay.

6. "MOP" means Minimum Operating Pool elevation as measured in feet above mean sea level in the reservoir forebay.

B. Except as provided in Paragraph 3 below, Federal Defendants shall implement the spill operations set forth in Table 1 below beginning in Spring 2026 and continuing until otherwise ordered by this Court.

Table 1: Injunction spill operation

Project	**Spring spill season (early April – mid-June)**	**Summer spill season (mid-June – end of August)**	**Fall/Winter spill season (early September – mid-November; early March – early April)** **Shutdown period Nov. 16 – Feb. 28/29 to address freezing issues and maintenance except as noted below.**
Lower Granite	Apr. 3 – June 20 125% Gas cap spill 24 hours per day	June 21 – Aug. 31 18 kcfs 24 hours per day	Sep. 1 – Nov. 15; and Mar. 1 – Apr. 2 Low volume surface passage via spillway weir (Bay 1 RSW) 24 hours per day
Little Goose	Apr. 3 – June 20	June 21 – Aug. 31	Sep. 1 – Nov. 15; and Mar. 1 – Apr. 2

Project	Spring spill season (early April – mid-June)	Summer spill season (mid-June – end of August)	Fall/Winter spill season (early September – mid-November; early March – early April) Shutdown period Nov. 16 – Feb. 28/29 to address freezing issues and maintenance except as noted below.
	125% Gas cap spill 24 hours per day until adult criteria reached[2] After adult criteria reached: 125% Gas cap spill 16 hours/day and 30% for 8 consecutive daytime hours.	30% spill 24 hours per day	Low volume surface passage via spillway weir (Bay 1 ASW @ high crest) 24 hours per day

[2] Little Goose Adult Criteria –Within 1 business day of when the earliest of the following conditions occurs: (1) a cumulative total of 25 adult spring Chinook salmon (not including jacks) pass Lower Monumental Dam; or (2) a cumulative total of 50 adult spring Chinook salmon (not including jacks) pass Ice Harbor Dam; or (3) April 24, 2026, the Corps will implement performance standard spill at Little Goose Dam for 8 consecutive AM hours (April 3–15 starting at 0500 hours; April 16–June 20 starting at 0400 hours) to target hours of peak adult passage. If lack of load conditions preclude the implementation of performance standard spill during the targeted periods, performance standard spill will begin as soon as practicable during AM hours and continue for up to 8 consecutive hours. If a second block is needed, it will start as soon as load conditions allow, continue for at least two consecutive hours, and conclude no later than 2000 hours.

Project	**Spring spill season (early April – mid-June)**	**Summer spill season (mid-June – end of August)**	**Fall/Winter spill season (early September – mid-November; early March – early April)** **Shutdown period Nov. 16 – Feb. 28/29 to address freezing issues and maintenance except as noted below.**
Lower Monumental	Apr. 3 – June 20 125% Gas cap spill (uniform spill pattern)[3,4] 24 hours per day	June 21 – Aug. 31 17 kcfs 24 hour per day	Sep. 1 – Nov. 15; and Mar. 1 – Apr. 2 Low volume surface passage via spillway weir (Bay 8 RSW) 24 hours per day
Ice Harbor	Apr. 3 – June 20 125% Gas cap spill 24 hours per day	June 21 – Aug. 31 30% 24 hours per day	Sep. 1 – Nov. 15; and Mar. 1 – Apr. 2 Low volume surface passage via spillway weir (Bay 2 RSW) 24 hours per day
McNary	Apr. 10 – June 15 125% Gas cap spill 24 hours per day	June 16 – Aug. 31 57% spill 24 hours per day	Sep. 1 – Nov. 15; and Mar. 1 – Apr. 9 Low volume surface passage via both spillway weirs (Bay 19 and Bay 20 TSWs) 24 hours per day

[3] Monitor and manage adult conversion rates in-season via Technical Management Team (TMT) process.

[4] Suspend juvenile fish transportation at Lower Monumental to avoid within day spill fluctuation.

Project	**Spring spill season (early April – mid-June)**	**Summer spill season (mid-June – end of August)**	**Fall/Winter spill season (early September – mid-November; early March – early April)** **Shutdown period Nov. 16 – Feb. 28/29 to address freezing issues and maintenance except as noted below.**
John Day	Apr. 10 – June 15 125% Gas cap spill 24 hours per day Powerhouse outflows may increase up to 80kcfs for reserves without requiring a spill variance.[5]	June 16 – Aug. 31 35% spill 24 hours per day	Sep. 1 – Nov. 15; and Mar. 1 – Apr. 9 Low volume surface passage via both spillway weirs (Bay 18 and Bay 19 TSWs) 24 hours per day Approximately 1.6 kcfs Bay 2 for adult attraction when adult ladder is watered up (not during winter maintenance).
The Dalles	Apr. 10 – June 15 40% spill up to 125% Gas cap spill[6] (Gas cap fish passage spill prioritizes spillbays 1-8 and Ice Trash Sluiceway) 24 hours per day	June 16 – Aug. 31 40% (fish passage spill prioritizes spill bays 1-8 and Ice Trash Sluiceway) 24 hours per day	Sep. 1 – Apr. 9 Ice Trash Sluiceway will operate at the lowest functional level using current FPP guidelines (~3 to 5 kcfs) 24 hours per day Scheduling routine or non-routine below waterline maintenance will be coordinated in FPOM.

[5] Increased powerhouse generation allowances will allow for additional generation to be brought on-line for the purpose of providing real-time operators greater access to reserve capacity prior to requiring variance tracking or declarations of power system emergency. As needed, these ranges will be utilized under low flow conditions (e.g., minimum generation and spill the rest) and when flexibility elsewhere has been maximized.

[6] TDG in The Dalles tailrace may fluctuate up to 125% prior to reducing spill at upstream projects or reducing spill at The Dalles below 40%. Maintain 40% spill for 24 hours at The

Project	**Spring spill season (early April – mid-June)**	**Summer spill season (mid-June – end of August)**	**Fall/Winter spill season (early September – mid-November; early March – early April)** **Shutdown period Nov. 16 – Feb. 28/29 to address freezing issues and maintenance except as noted below.**
Bonneville	Apr. 10 – June 15 125% Gas Cap spill with upper limit to 150 kcfs until stilling basin maintenance is complete (Prioritizes concurrent operation of spillway, Power House 1 Ice Trash Sluiceway, and Power House 2 Corner Collector) 24 hours per day	June 16 – Aug 31 95 kcfs plus Powerhouse 1 Ice Trash Sluiceway and Powerhouse 2 Corner Collector 24 hours per day	Sep. 1 – Apr. 9 Powerhouse 1 Ice Trash Sluiceway will operate 24 hours per day Sep. 1 – Apr. 9 Powerhouse 2 Corner Collector will operate 24 hours per day Sep. 1 – Apr. 9 Adult attraction 24 hours per day Scheduling routine or non-routine below waterline maintenance will be coordinated in FPOM.

1. "Zero Generation Operations" as described in the 2020 CRSO EIS ROD will no longer commence as early as October 15, and will instead commence once the implementation trigger described in System Operational Request ("SOR") 2005-22 has been met. This trigger will be

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Dalles and reduce John Day spill below the 125% TDG spill cap as needed for TDG management. Spill above 40%, up to 125% TDG, may occur for TDG management or for carrying reserves.

implemented in relation to both date (implementation will be limited to periods between December 1 through February 28) and abundance.

2. The annual FOP will be used by the Federal Defendants in determining spill patterns, processes, and procedures for implementation of the operations in Table 1 and the Zero Generation Operations stated above.

3. Federal Defendants may make planned or un-planned adjustments to the injunction spill operation for the reasons set forth in the annual FOP and following the procedures set forth in the annual FOP, including deference provided to the Action Agencies for energy emergencies, human safety, or infrastructure integrity emergencies.

   a. Any adjustments taken under this paragraph shall be limited to addressing the condition(s) at issue and shall not otherwise alter the injunction spill operation.

   b. Federal Defendants shall restore the injunction spill operation as soon as practicable after the condition requiring adjustment is addressed.

   c. Beginning in 2026, Water Management Plans and FOPs must require, before curtailing voluntary spill to help carry energy reserves (e.g., as outlined in the 2025 FOP)—except as specified above for the spring period at John Day dam—due diligence implementation of preemptive actions, as well as a declaration of power system emergency and/or spill variance reporting.

d. Deviations from spill orders, including rationale and resolution, shall be updated regularly on electronic platforms available to regional sovereigns.

C. Reservoir Forebay Elevation Operations Injunction

Commencing in 2026 and until otherwise ordered by the Court, the Federal Defendants shall operate all reservoir forebay elevations operations using the operation ranges from 2025.[7] By July 1st of each year, the Federal Defendants shall provide a summary to regional fish managers of which operational criteria and authorized purposes are associated with pool elevation lower limits that exceed the required ranges for each of the dams. For Bonneville, The Dalles, and McNary dams, this summary will include a description of when and why any operation limits increased from the original designations, and what actions are needed to return to designated elevations.

D. Non-Operational Conservation Measures

The Federal Defendants included in the 2020 BiOp measures for steelhead kelt reconditioning, avian and non-native piscine predation reduction, and Snake River Sockeye transportation. Thus, the Court did not grant this requested relief, even though it would provide immediate benefit to the listed species. The Court directs the government to file quarterly reports on the status of the implementation of each of these measures. Plaintiffs have leave to file on an

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[7] The Court allows Defendants a reasonable period of time, not to exceed two weeks from the date of this Order, to implement this Order.

In the Order, the Court set forth the ranges as represented in ECF 2665 at 6. *See* ECF 2668 at 9. Plaintiffs sought clarification regarding reservoir levels, contending that the elevations for the four Lower Snake River dams were from the 2020 BiOp, rather than from the 2025 FOP. *See* ECF 2669 at 3. As stated above, the Court orders implementation of reservoir levels at the actual 2025 operating levels. To avoid the potential of conflicting orders, the Court removes the previously-listed ranges in this Amended Preliminary Injunction Order.

expedited basis a renewed motion for preliminary injunctive relief if the government is not pursuing these measures as anticipated in the 2020 BiOp.

IT IS SO ORDERED.

DATED this 2nd day of March, 2026.

Michael H. Simon
United States District Judge

Appendix 1

Technical Management Team Emergency Protocols

COLUMBIA RIVER SYSTEM

FOR ATTACHMENT TO THE
WATER MANAGEMENT PLAN
AND OTHER APPROPRIATE ACTION PLANS

Updated December 5, 2025

1. Introduction

This document establishes a protocol that will be used by the Action Agencies for notification, consultation, and documentation in the event of an emergency concerning the operation of the Columbia River System (CRS) that impacts fish protection measures contained in the respective Biological Opinions (BiOps). The BiOps call for an annual Water Management Plan (WMP), which provides the detailed description of operations, based on the current year conditions, to ensure fish protection measures are consistent with Endangered Species Act responsibilities. This Protocol is meant to be general enough to encompass most kinds of emergencies. This Protocol pertains to short duration (approximately 1-7 days) interruptions or adjustments to protection measures for listed species that occur during the operation of the CRS.

The primary emergency types these protocols apply to are:

- Generation Emergency: the potential for or actual insufficiency of electrical generation to satisfy electrical demand or load.
- Transmission Emergency: the potential or actual loss or limitation in the ability to move electricity from the site of generation to the actual consumer or end-user.
- Fish Emergency: Unexpected equipment failures or other conditions that result in an interruption of fish protections measures.
- Other Emergency: the existence or result of extenuating circumstances which fall outside the range of normal operations, is unanticipated, and may significantly impair the ability to provide for other project uses, such as flood control or navigation, significant human health and safety concerns, or result in catastrophic impact, physical damage or failure to a dam, or other part of the physical power system. Examples include earthquakes, flood control operations, fires, navigation, dam safety, and failure of fish facilities infrastructure.

Specific Action Plans will be developed for Generation *(Completed-See Attachment 1)*, Transmission and Fish Emergencies that identify pre-emptive actions and emergency actions that will be taken consistent with this Protocol. Examples of thresholds for these types of emergencies are shown in the respective Action Plans contained in Attachments 1 and 2 of this Protocol. Action Plans are coordinated in the TMT process.

The degree and/or nature of any emergency ranges from those that require immediate action to those that are amenable to coordination among affected parties prior to action. In some instances, it is possible to plan for and develop procedures to respond to an emergency, while in other instances this is not possible. In addition, while many types of emergencies can be described for purposes of this Protocol, not all emergencies can be identified prior to the actual occurrence. Discussion of emergencies with effects of exceptional magnitude or duration will include involvement of regional executives.
Emergency actions will not be taken in place of long-term investments necessary to allow full uninterrupted implementation of the planned reservoir and dam operations while maintaining other project purposes.

Interruptions to protection measures for non-listed species are inclusive in these Protocols; however, priority will be given to protection measures for listed species.

2. Goals

The primary goal of this Protocol is to have written procedures that describe how the Action Agencies will manage the CRS to avoid or minimize emergencies impacting fish protection measures in accordance with ESA biological opinions and other operative documents such as the WMP, and provide timely communication and coordination with the TMT when they occur. When emergencies occur, the Action Agencies will work with TMT to restore the protection measures and provide the planned life cycle survival rates with priority given to in-time and in-place actions to the extent practicable. (*This does not create legal rights or obligations on the part of any party.*)

3. Definitions:

Emergency – A sudden, urgent, usually unforeseen occurrence or occasion requiring immediate action. As applied to this Protocol: when necessary, interruptions or adjustments occur to fish protection measures identified in the applicable biological opinions, the Annual Water Management Plan, and other operative documents.

Emergency Actions- Actions taken by the Action Agencies in response to an emergency that affects fish protection measures.

Action Agencies - Bonneville Power Administration (BPA), Corps of Engineers (COE or Corps), and the Bureau of Reclamation (BOR or Reclamation)

TMT - Technical Management Team is one of the Regional Forum technical teams. Adaptive management of the CRS is coordinated in the Technical Management Team public meeting process.

Water Management Plan. - The Water Management Plan (WMP) describes how the Action Agencies plan to operate the Columbia River System (CRS) projects in accordance with the governing documents identified in Section 2 of the TMT Annual Water Management Plan.

4. Emergency Protocol

4.1. Advanced Planning – Pre-Emptive Actions

When the operation of the CRS is likely to require implementing emergency actions and the event can be anticipated approximately 24 hours in advance or earlier, the Action Agencies will convene a meeting of the TMT to discuss actions to undertake with the objective of averting or minimizing impacts to fish protection measures. This Protocol contains an Action Plan (see Attachment 1) that describes pre-emptive actions that will be pursued to avoid interrupting fish protection measures.

When conditions are identified that could potentially require the use of Emergency Actions within approximately 24 hours, the responsible agency, i.e. the Action Agency which would declare the emergency, shall notify the chair and co-chairs(s) of the TMT as soon as the

situation is observed. If there is time, a TMT call or meeting will be arranged by the TMT chair or co-chair(s). If time allows, a discussion will be arranged, however, in some situations, the call may provide notification to TMT members of pre-emptive actions the responsible agency has deemed necessary.

The Action Agencies will implement all available pre-emptive actions prior to implementing emergency actions, and when feasible, the Action Agencies will implement alternate operations recommended by TMT.

4.2. Emergency Response

Emergency actions may be required as an immediate response if the pre-emptive actions fail to resolve the situation or the situation deteriorates without warning. If emergency actions are implemented as an immediate response an emergency will be declared. The Agency declaring the emergency will consider the prioritized emergency action lists provided in appendices of this Protocol, direction from TMT or other groups, standard operating procedures for specific projects, and/or guidance from appropriate responsible agencies to resolve the condition.

The Action Plans provided in the appendices of this Protocol have been discussed in the TMT forum will be used as guidance when events unfold too quickly for pre-coordination to occur. For emergencies requiring immediate action by those operating the respective hydropower project(s) or other elements necessary to sustain the function of the hydrosystem, after stabilizing the situation they will contact the chairs of the TMT and IT. The TMT chair or co-chair(s) will disseminate a notification via phone calls and emails to a "first contact list," which will include designated members from TMT and others that have requested inclusion on the first contact list as soon as practicable, but not later than the next working day. A meeting of the TMT will be convened at the earliest time available after notification of the first contacts.

5. Documentation and Follow Up Requirement

In all cases when emergency actions have been implemented, as soon as practicable, but not later than the next working day, the following information shall be provided by the agency declaring the emergency:

- Description of the emergency, how it occurred, and how long it is anticipated to last
- Description of how the emergency jeopardized system stability, public safety, or otherwise necessitated action that impacted fish protection measures.
- Identification of agencies that declared the emergency and agencies that responded to the emergency
- Identification of who was notified of the emergency
- Description of what actions were taken by each agency
- Identification of alternatives considered to reduce and offset impacts of the emergency.
- Further detailed information will be provided upon request of the TMT.

When requested by a TMT member, the TMT Chairperson will arrange for a follow-up TMT meeting or conference call to:

- Review status of the event,
- Ensure that all requirements for the implementation of emergency actions by the Action Agencies have been met and that all alternatives for offsetting adverse fish survival impacts of the implemented emergency actions have been considered, and
- Review the use of emergency action lists and revise the lists based on any lessons learned.

In general, system operations will revert to normal conditions, or as agreed upon in the TMT, when the event has been resolved or emergency actions are no longer required. The agency that declared the emergency will submit a detailed report of the incident and response at the next TMT meeting following the event unless other arrangements are arranged through the TMT process.

The Action Agencies will provide an opportunity for representatives of the region's affected parties to review the course of events and the implemented emergency actions to suggest refinements to the actions. These issues will be discussed at the next TMT meeting following the event.

6. Offsetting Adverse Effects of Emergency Response Actions

When emergency actions are implemented that cause adverse effects to fish protection measures, the TMT will assess the magnitude of the adverse effect and provide information on measures available to offset these effects. Alternative operations to offset adverse effects in-place and in-kind in a timely manner shall receive the highest priority. The members of the Regional Forum agree to cooperate in the development of this information for consideration through the TMT process.

When emergency actions impact a fish protection measure(s) included in a Biological Opinion, the appropriate agency (National Marine Fisheries Service (NMFS) or Fish and Wildlife Service (USFWS)) will consider the available information to assess whether the alternative operation used in response to the emergency situation is inconsistent with the relevant Biological Opinion(s), in that, in its expert opinion, the effects were in excess of what was contemplated in the analyses used in the respective biological opinion. If the alternative operation is determined to provide a reduction in the life cycle survival rate than that recommended in the Biological Opinion(s) analyses, then NMFS or USFWS will recommend to the federal operating agencies offsetting measures to ensure that the action satisfies Endangered Species Act requirements.

An Action Agency deciding not to provide offsets or proposing offsetting actions that are different from those recommended through the TMT process, will provide a written explanation for the record stating the decision and the basis for the decision.

Emergency Protocols Attachment

Attachment 1 – Power System Emergency Action Plan

Attachment 1

Power System Emergency Action Plan

December 5, 2025

If hydropower generation must be adjusted to support power system reliability, and this adjustment will alter planned fish operations specified in applicable biological opinions (and other guiding operative documents), Bonneville will attempt to implement the actions in the preemptive actions list below, where practicable. If these preemptive actions are unavailable, insufficient, or cannot be implemented in time, then Bonneville may implement additional actions as necessary to address the power system reliability need. The list of contingency actions below are examples of actions that can be taken to address the reliability conditions described in Section 4.4.2 of the FOP.

Where contingency action is necessary, notification to the region will be made as soon as practical, and will follow the protocols for notification, reporting, and documentation as specified in the *Technical Management Team Emergency Protocols, Appendix 1 – Emergency Protocols of the TMT Water Management Plan.*

Pre-emptive Actions (not in priority order)

- Purchase Energy and/or reserves at prices up to the applicable FERC WECC price cap.
- Request that Corps and Reclamation return all possible units to service by canceling or postponing scheduled generator or equipment outages (e.g., makes all units available).
- Request the transmission dispatcher consider adjusting transmission system maintenance or other possible actions that would allow increases or decreases in CRS generation as appropriate.
- Put into service (online) all possible generators (e.g., Grand Coulee pump-generators) while preserving sufficient energy storage to maintain reserve capability in subsequent hours
- Reshape flows within objectives at specific projects to meet immediate generation needs e.g., spill upstream projects to position water downstream.
- Cut any interruptible power commitments.
- Request adjustment of pumping schedule at Banks Lake.
- Request variance from non-power operational objectives or limits at CRS hydro projects (e.g., forebay draft limits, tailwater rate of change, recreation, irrigation, Treaty fishing, etc.)
- Reduce the amount of balancing reserves provided by the CRS to the minimum amount necessary for power system stability and reliability.
- Acquire any resources made available through the issuance of a "EEA Watch".
- After exhausting all available reserve sharing opportunities ask the transmission dispatcher to request the Reliability Coordinator to declare an Energy Emergency ALERT 1 when there is concern about sustaining required operating reserves.

Contingency Actions List

(Updated February 25, 2022)

When routine reliability tools and preemptive actions are insufficient or unavailable to resolve the power system condition, the following is a list of contingency actions that may be taken to provide reserves, voltage, energy or inertia. The order and extent of the actual implementation of the actions in this list will be dictated by each specific condition but if possible, the order at each individual dam will be followed. The actions on the list may be updated as necessary through coordination with TMT.

Contingency Actions are prioritized by tier and within each tier.

March 1 – April 2	April 3 – April 9	April 10 – June 15	June 16 – June 20
Tier 1	Tier 1	Tier 1	Tier 1
LWG Move Spillway Weir Hours within morning hours or next day morning	JDA shutoff adult attraction spill	**BON**: Generate above 1% up to full load PH1	**BON**: Generate above 1% up to full load PH1
LGS Move Spillway Weir Hours within morning hours or next day morning	BON shutoff adult attraction spill	**TDA**: Generate above 1% up to full load	**TDA**: Generate above 1% up to full load
LMN Move Spillway Weir Hours within morning hours or next day morning	HGH, LIB, ALF, GCL: increase project drafts as coordinated with operators	**JDA**: Generate above 1% up to full load	**JDA**: Generate above 1% up to full load
IHR Move Spillway Weir Hours within morning hours or next day morning	HGH & LIB modify ramping rates as coordinated with operators	**MCN**: Generate above 1% up to 14.4 kcfs/unit	**MCN**: Generate above 1% up to 14.4 kcfs/unit
MCN Move Spillway Weir Hours within morning hours or next day morning	DWR: increase project drafts as coordinated with operators	**IHR**: Generate above 1% up to full load	**IHR**: Generate above 1% up to full load
		LMN: Generate above 1% up to full load	**LMN**: Generate above 1% up to full load
		LGS: Generate above 1% up to full load	**LGS**: Generate above 1% up to full load
		LWG: Generate above 1% up to full load	**LWG**: Generate above 1% up to full load
		Allow MOP excursion up to: 2 feet at IHR, LMN, LGS, and LWG (w/o reduction in FOP spill levels)	Allow MOP excursion up to: 2 feet at IHR, LMN, LGS, and LWG (w/o reduction in FOP spill levels)

Appendix I, Water Management Plan

March 1 – April 2	April 3 – April 9	April 10 – June 15	June 16 – June 20
Tier 2	**Tier 2**	**Tier 2**	**Tier 2**
JDA shutoff adult attraction spill	IHR 30% of flow	LWG reduce spill to 20 kcfs	LWG reduce spill to 20 kcfs
BON shutoff adult attraction spill	LMN 30 kcfs flat	LGS reduce spill to 30% of flow	LGS reduce spill to 30% of flow
HGH & LIB modify ramping rates	LGS 30% of flow	IHR reduce spill to 30% of flow	IHR reduce spill to 30% of flow
HGH, LIB, ALF, GCL : increase project drafts	LWG 20 kcfs	MCN reduce spill to 40% of flow	MCN reduce spill to 40% of flow
DWR: increase project drafts		JDA reduce spill to 30% of flow	JDA reduce spill to 30% of flow
		TDA reduce spill to 30% of flow	TDA reduce spill to 30% of flow
		BON reduce spill to 100 kcfs	MCN generate outside 1% up to full load
		MCN generate outside 1% up to full load	BON2 operate outside 1% up to full load
		BON PH2 operate outside 1% up to full load	Allow MOP excursion up to 3 feet at IHR, LMN, LGS, and LWG
		Allow MOP excursion up to 3 feet at IHR, LMN, LGS, and LWG	
Tier 3	**Tier 3**	**Tier 3**	**Tier 3**
BON1 shut off sluiceway	BON shut off sluiceway	LWG reduce spill to 18 kcfs	LWG 18 kcfs of spill
TDA shut off sluiceway	TDA shut off sluiceway	LMN reduce spill to 30% of flow	LMN 30% of flow
BON shut off B2CC	BON shut off B2CC	MCN reduce spill to 30% of flow	MCN 30% of flow
		BON 95 kcfs	BON 50 kcfs
		BON: Generate above 1% up to full load PH2	BON: Generate above 1% up to full load PH2

Appendix I, Water Management Plan

March 1 – April 2	April 3 – April 9	April 10 – June 15	June 16 – June 20
Tier 4	**Tier 4**	**Tier 4**	**Tier 4**
	LWG Reduce Spill to Spillway weir only	BON 75 kcfs	BON 75 kcfs
	LGS Reduce Spill to Spillway weir only	LWG Reduce Spill to Spillway weir only	LWG Reduce Spill to Spillway weir only
	LMN Reduce Spill to Spillway weir only	LGS Reduce Spill to Spillway weir only	LGS Reduce Spill to Spillway weir only
	IHR Reduce Spill to Spillway weir only	LMN Reduce Spill to Spillway weir only	LMN Reduce Spill to Spillway weir only
		IHR Reduce Spill to Spillway weir only	IHR Reduce Spill to Spillway weir only
		MCN Reduce Spill to Spillway weir only	MCN Reduce Spill to Spillway weir only
Tier 5	**Tier 5**	**Tier 5**	**Tier 5**
	Reduce spill to zero at LWG	BON reduce spill to 50 kcfs	BON reduce spill to 50 kcfs
		BON reduces spill to zero	BON reduces spill to zero
	Reduce spill to zero at LGS	BON shutdown B1 Sluiceway	BON shutdown B1 Sluiceway
	Reduce spill to zero at LMN	BON shutdown B2CC	BON shutdown B2CC
	Reduce spill to zero at IHR		
Tier 6	**Tier 6**	**Tier 6**	**Tier 6**
		LWG reduce spill to zero	LWG reduce spill to zero
		LGS reduce spill to zero	LGS reduce spill to zero
		LMN reduce spill to zero	LMN reduce spill to zero
		IHR reduce spill to zero	IHR reduce spill to zero
		MCN reduce spill to zero	MCN reduce spill to zero
		JDA reduce spill to zero	JDA reduce spill to zero
		TDA reduce spill to zero	TDA reduce spill to zero

Appendix I, Water Management Plan

June 21 – August 14	August 15 - August 31	September – November 15	November 16 - End of Feb
Tier 1	Tier 1	Tier 1	Tier 1
BON: Generate above 1% up to full load PH1	**BON**: Generate above 1% up to full load PH1	LWG Move Spillway Weir Hours within morning hours or next day morning	HGH, LIB, ALF, GCL: increase project drafts
TDA: Generate above 1% up to full load	**TDA**: Generate above 1% up to full load	LGS Move Spillway Weir Hours within morning hours or next day morning	HGH & LIB modify ramping rates
JDA: Generate above 1% up to full load	**JDA**: Generate above 1% up to full load	LMN Move Spillway Weir Hours within morning hours or next day morning	BON shut off sluiceway
MCN: Generate above 1% up to 14.4 kcfs/unit	**MCN**: Generate above 1% up to 14.4 kcfs/unit	IHR Move Spillway Weir Hours within morning hours or next day morning	TDA shut off sluiceway
IHR: Generate above 1% up to full load	**IHR**: Generate above 1% up to full load	MCN Move Spillway Weir Hours within morning hours or next day morning	Dworshak increase project drafts
LMN: Generate above 1% up to full load	**LMN**: Generate above 1% up to full load		
LGS: Generate above 1% up to full load	**LGS**: Generate above 1% up to full load		
LWG: Generate above 1% up to full load	**LWG**: Generate above 1% up to full load		
Allow MOP excursion up to: 2 feet at IHR, LMN, LGS, and LWG (w/o reduction in FOP spill levels)	**BON**: Generate above 1% up to full load PH2		

Appendix I, Water Management Plan

June 21 – August 14	August 15 - August 31	September – November 15	November 16 - End of Feb
Tier 2	**Tier 2**	**Tier 2**	**Tier 2**
LWG Reduce Spill to Spillway weir only	LWG reduce spill to zero	JDA shutoff adult attraction spill	
LGS Reduce Spill to Spillway weir only	LGS reduce spill to zero	BON shutoff adult attraction spill	
IHR Reduce Spill to Spillway weir only	LMN reduce spill to zero	HGH, LIB, ALF, GCL : increase project drafts	
MCN 40% of flow	IHR reduce spill to zero	HGH & LIB modify ramping rates	
JDA 30% of flow	MCN reduce spill to zero		
TDA 30% of flow	JDA reduce spill to zero		
BON 75 kcfs	BON reduce spill to zero		
MCN generate outside 1% up to full load	TDA reduce spill to zero		
BON PH2 operate outside 1% up to full load			
Allow MOP excursion up to 3 feet at IHR, LMN, LGS, and LWG			
Tier 3	**Tier 3**	**Tier 3**	**Tier 3**
MCN 30% of flow	BON1 shut off sluiceway	LWG reduce spill to zero	
JDA Spillway Weir only	TDA shut off sluiceway	LGS reduce spill to zero	
BON 50 kcfs	BON shut off B2CC	LMN reduce spill to zero	
IHR reduce spill to zero		IHR reduce spill to zero	
LMN reduce spill to zero		MCN reduce spill to zero	
LGS reduce spill to zero		BON1 Shut off sluiceway	
LWG reduce spill to zero		TDA Shut off sluiceway	

June 21 – August 14	August 15 - August 31	September – November 15	November 16 - End of Feb
Tier 4	Tier 4	Tier 4	Tier 4
BON reduce spill to zero		DWR: increase project drafts	
TDA reduce spill to zero			
Tier 5	Tier 5	Tier 5	Tier 5
Tier 6	Tier 6	Tier 6	Tier 6

Definitions

Balancing Authority - The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

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.

BPA Power system – This term includes the Federal Columbia River hydropower projects and transmission system.

Energy Emergency Alerts – Procedures by which a Load Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. An Energy Emergency Alert may be initiated by Reliability Coordinator at the Reliability Coordinator's own request or upon the request of a Balancing Authority or a Load Serving Entity. See: https://www.caiso.com/documents/emergency-notifications-fact-sheet.pdf

Energy Emergency Watch - The EEA Watch is a communication tool that provides load serving entities a means to exchange information regarding issues that could impact the reliable operation of the power system when analysis shows all available resources are committed or forecasted to be in use, and energy deficiencies are expected. This notice can be issued the day before the projected shortfall or if a sudden event occurs. Consumers are encouraged to conserve energy.

Energy Emergency Alert 1 - All available resources in use.

- Balance Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and
- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

Energy Emergency Alert 2 – Load management procedures in effect.

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customer' expected energy requirements, and is designated an Energy Deficient Entity.
- Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments.

Energy Emergency Alert 3 – Firm load interruption imminent or in progress.

- Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

Energy Emergency Alert 0 - Termination

- When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of its Reliability Coordinator that the Energy Emergency be terminated.

Redispatch – The intentional incrementing of location-specific generation and the corresponding decrementing of different location-specific generation to mitigate loading on constrained transmission facilities.

DEPARTMENT OF THE ARMY
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2025 Fish Operations Plan

1. INTRODUCTION

The 2025 Fish Operations Plan (2025 FOP) describes the U.S. Army Corps of Engineers' (Corps) planned operations for fish[1] passage at its four lower Snake River and four lower Columbia River dams and includes spring surface spill operations (March through early April), spring and summer spill operations (early April through August), and fall/winter surface spill operations (September through mid-November). The 2025 FOP is consistent with spill operations for fish passage and the regional forum process for adaptive management and in-season management provisions outlined in the Record of Decision for the Columbia River System Operations Environmental Impact Statement (CRSO EIS ROD) dated September 28, 2020, CRSO Final EIS, 2020 National Marine Fisheries Service (NMFS) and U.S. Fish and Wildlife Service (USFWS) Columbia River System (CRS) Biological Opinions (2020 CRS BiOps)[2], the Extensions of the 2008 Columbia Basin Fish Accords (Accord Extensions), the Corps' requirements under the Endangered Species Act (ESA), and the ongoing consultation and communications with the relevant wildlife agencies to ensure consistency with the Act. The 2025 FOP also incorporates operations outlined in Appendix B of the "U.S. Government Commitments in Support of the Columbia Basin Restoration Initiative" (USG Commitments). The USG Commitments were agreed to as part of the 2023 Memorandum of Understanding (*see* Section 3 of the MOU). Other project operations and water management actions not specifically addressed in this document will be consistent with other guiding operative documents, including the 2025 Water Management Plan (WMP), seasonal WMP updates, and the 2025 Fish Passage Plan (FPP).

In addition to discussing project-specific fish passage spill operations, the 2025 FOP identifies factors that the Corps, the Bureau of Reclamation (Reclamation), and the Bonneville Power Administration (Bonneville) (collectively referred to as the "Action Agencies") must address in the context of operating this complex system of fourteen multiple purpose projects. The 2025 FOP includes a discussion of how the Corps manages fish passage spill and total dissolved gas (TDG), identifies Planned and Routine Operational Adjustments (Section 4) that influence fish passage spill, addresses adaptive management and in-season management processes for fish passage spill and other fish operations including the juvenile fish transportation program, and describes the Corps' monthly implementation reports.

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[1] ESA-listed salmon and steelhead.
[2] The Corps, in coordination with the other Action Agencies, and NMFS, employs the Regional Implementation Oversight Group (RIOG) and technical teams including the Technical Management Team (TMT) and Fish Passage Operations & Maintenance (FPOM) coordination group, to coordinate with state, tribal and other federal experts for recommendations for implementing operations consistent with the 2020 BiOps.

2. MANAGEMENT OF SPILL FOR FISH PASSAGE AND TDG

2.1. State Water Quality Standards for TDG

The Corps will manage spill for fish passage in 2025 consistent with the State of Washington and the State of Oregon total dissolved gas (TDG) water quality standards (WQS).[3,4] The State of Washington, Department of Ecology (WADOE) adopted a WQS rule change which became effective in 2020 allowing spring juvenile fish passage spill operations to generate specified TDG levels in project tailraces (up to 125% TDG 12 hours, 126% TDG 2 hours), so long as the specified conditions are met, including that spring juvenile fish passage spill operations do not exceed the spill levels and durations reviewed in applicable ESA consultation documents. The Environmental Protection Agency (EPA) subsequently approved the rule change and found that the ESA consultation documents ensure that any spring spill regime using the revised criteria must be performed in accordance with the spill levels and durations evaluated in ESA consultation documents for effects to ESA-listed species of all life stages, including juvenile out-migrating salmonids, resident salmonids, and adult migrating salmonids. EPA's approval of the rule further states that "compliance with the ESA consultation documents is a condition precedent for the revised criteria and so the criteria are not applicable for the purposes of the [Clean Water Act (CWA)] (i.e., have no effect for CWA purposes) without the ESA consultation documents addressing spill operations that result in TDG saturation levels above the pre-existing criterion." *Letter to WADOE from EPA Re: The EPA's Action on Revisions to the [WADOE's] Surface Water Quality Standards for the Site-Specific Total Dissolved Gas Criteria in the Columbia and Snake Rivers, and Other Water Quality Standards Revisions* dated March 5, 2020, page 9.

The State of Oregon, through its Environmental Quality Commission, approved a modification to its TDG WQS of up to 125% TDG from April 1-June15 and up to 120% TDG from June 16-August 31, so long as spring spill is "applied in a manner consistent with the applicable requirements of the federal [ESA]." (*Order Approving a Modification to the Oregon's Water Quality Standard for Total Dissolved Gas in the Columbia River Mainstem* dated December 31, 2024, page 4). Regarding Oregon's 105% TDG criterion, Oregon Department of Environmental Quality (ODEQ) clarified that this criterion does not apply to the Columbia River per their letter dated January 29, 2024. Both states have thus accommodated levels of TDG above 110% for fish passage spill operations for ESA-listed juvenile salmonids at Corps projects on the lower Snake and lower Columbia rivers, as follows:

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[3] WASH. ADMIN. CODE § 173-201A-200(l)(f)) provides the maximum TDG criteria for each of the aquatic life use categories and displays Table 200 (I)(f) that states: "Total dissolved gas shall not exceed 110 percent of saturation at any point of sample collection." The code also addresses exceptions and adjustments, including a provision allowing for an adjustment of the TDG criteria to aid fish passage over hydroelectric dams. *See* https://apps.leg.wa.gov/WAC/default.aspx?cite=173-201A-200.

[4] OR. ADMIN. R. 340-041-0031 provides in part: "the concentration of TDG relative to atmospheric pressure at the point of sample collection may not exceed 110 percent of saturation." OR. ADMIN. R. 340-041-104(3) identifies findings the Environmental Quality Commission must make for the purpose of allowing increased spill for salmon migration. *See* https://www.oregon.gov/deq/wq/Documents/columbiaUSACEtmdlorder.pdf

Washington Administrative Code[5]:

WAC 173-201A-200(1)(f)(ii) and WAC 173-201A-200(1)(f)(ii)(A)

(ii) The TDG criteria may be adjusted to aid fish passage over hydroelectric dams that spill for anadromous juvenile fish as of the 2020 spill season. The elevated TDG levels are intended to allow increased fish passage without causing more harm to fish populations than caused by turbine fish passage. The following special fish passage exemptions for the Snake and Columbia Rivers apply when spilling water at dams is necessary to aid fish passage:

(A) TDG must not exceed:

• An average of 115 percent as measured in the forebays of the next downstream dams and must not exceed an average of 120 percent as measured in the tailraces of each dam (these averages are calculated as an average of the 12 highest hourly readings in a calendar day, relative to atmospheric pressure); and
• A maximum TDG saturation level of 125 percent calculated as an average of the two highest hourly TDG measures in a calendar day during spillage for fish passage.

WAC 173-201A-200(1)(f)(ii)(B)

(B) To further aid fish passage during the spring spill season (generally from April through June), spill may be increased up to the following levels as measured at the tailrace fixed site monitoring location:

• A maximum TDG saturation level of 125 percent calculated as an average of the 12 highest hourly TDG measures in a calendar day: and
• A maximum TDG saturation level of 126 percent calculated as an average of any two-consecutive hourly TDG measures. These TDG criteria may be applied in place of (f)(ii)(A) of this subsection during spring spill operations when applied in accordance with the following conditions:

(I) In addition to complying with the requirements of this chapter, the tailrace maximum TDG criteria at hydropower dams shall be applied in accordance with Endangered Species Act consultation documents associated with spill operations on the Snake and Columbia rivers, including operations for fish passage. The Endangered Species Act consultation documents are those by which dams may legally operate during the time that the adjusted criteria in (f)(ii)(B) of this subsection are in use.

(II) Application of the tailrace maximum TDG criteria must be accompanied by a department approved biological monitoring plan designed to measure impacts of fish exposed to increased TDG conditions throughout the spring spill season. Beginning in

[5] The text of the code is copied verbatim below for reference.

the year 2021, plans must include monitoring for non-salmonid fish species and must continue for a minimum of five years, and thereafter as determined by the department.

(III) TDG must be reduced to allowances specified in (f)(ii)(A) of this subsection if the calculated incidence of gas bubble trauma in salmonids (with a minimum sample size of 50 fish required weekly) or non-salmonids (with a minimum sample size of 50 fish required weekly) exceeds:

- Gas bubble trauma in non-paired fins of 15 percent; or
- Gas bubble trauma in non-paired fins of five percent and gas bubbles occlude more than 25 percent of the surface area of the fin.

In accordance with WADOE's Rule Implementation Plan, if gas bubble trauma exceeds these biological thresholds, additional monitoring must demonstrate the incidence of gas bubble trauma below biological thresholds before TDG can be adjusted to allowances specified in this subsection. Gas bubble trauma monitoring data shall be excluded from comparison to biological thresholds when higher than normal river flow contributes to excess spill above the ability to meet (f)(ii)(B) of this subsection. This monitoring data exclusion shall apply for one full calendar day after reduced river flow allows attainment of (f)(ii)(B) of this subsection.

Oregon Water Quality Standard Modification:

The Environmental Quality Commission approved the following modification[6] to the statewide standard for total dissolved gas (OAR 340-41-0031(2)) of 110 percent for the lower Columbia River at McNary, John Day, The Dalles and Bonneville dams, as provided for in OAR 340-41-0104(3):

1. The total dissolved gas standard for the Columbia River as measured in the tailraces of McNary, John Day, The Dalles, and Bonneville dams is 125 percent for the period from April 1 through June 15.

2. The total dissolved gas standard for the Columbia River as measured in the tailraces of McNary, John Day, The Dalles, and Bonneville dams is 120 percent for the period from June 16 through Aug. 31.

3. These limits do not apply when the stream flow exceeds the seven-day, ten-year frequency flood.

4. The modified total dissolved gas standards will apply for five years, beginning Jan. 1, 2025, through Dec. 31, 2029 (calendar years 2025, 2026, 2027, 2028, and 2029).

5. The DEQ Director may approve additional periods of application of this modification up to 120 percent total dissolved gas as calculated in 8.a)i., beyond the April 1 to Aug. 31 period, subject to subsections 8.a) to 8.c) for reasons including passing Spring Creek

[6] The text of the modification is copied verbatim below for reference.

Hatchery fish releases and other voluntary fish passage operations, maintenance activities, and biological or physical studies of spillway structures and prototype fish passage devices. The Corps must notify DEQ in writing at least one week prior to the spill describing the proposed action, including its purpose, and the location and dates of elevated total dissolved gas levels. Spill must be reduced to meet the 110 percent total dissolved gas criterion if requested by the DEQ Director.

6. Application of the tailrace maximum TDG criteria must be accompanied by a DEQ-approved biological monitoring plan designed to measure impacts to fish exposed to increased TDG conditions. Plans must include monitoring for non-salmonid fish species. Gas bubble trauma monitoring may be halted if there is a high mortality risk due to compounded effects of the evaluation procedure and adverse environmental factors such as high stream temperatures.

7. Voluntary fish passage spill during the spring spill season, occurring from April 1 through June 15, is subject to the following conditions:

   a. Spill at a dam must be reduced when:

      i. Instantaneous total dissolved gas levels exceed 127 percent of saturation, calculated as the average of any two consecutive hourly TDG measurements in the tailrace of the dam; or

      ii. The average of the twelve highest hourly TDG measurements in the tailrace of the dam in a calendar day exceeds 125 percent.

   b. The DEQ Director may halt the voluntary spill program or require reductions in voluntary spill to reduce TDG levels to 120 percent as calculated in 8.a)i. when:

      i. The calculated incidence of gas bubble trauma in salmonids (with a minimum sample size of fifty fish required weekly) or non-salmonids (with a minimum sample size of fifty fish required weekly) exceeds gas bubble trauma in eyes or non-paired fins of fifteen percent, or gas bubble trauma in eyes or non-paired fins of five percent and gas bubbles occlude more than twenty-five percent of the surface area of the fin or eyes. If gas bubble trauma exceeds these biological thresholds and spill is reduced, additional monitoring must demonstrate the incidence of gas bubble trauma below biological thresholds before TDG can be increased to the level specified in this order. Gas bubble trauma monitoring data shall be excluded from comparison to biological thresholds when higher than normal river flow contributes to excess spill above 125 percent. This monitoring data exclusion shall apply for one full calendar day after reduced river flow allows attainment of 125 percent TDG levels in the tailrace of the dam.

   c. The tailrace maximum TDG criteria for spring spill in this modification will be applied in a manner consistent with the applicable requirements of the federal Endangered Species Act.

d. Physical monitoring must occur and be adequate for implementing the requirements of this order.

8. Voluntary fish passage spill during the summer spill season, occurring from June 16 through Aug. 31, is subject to the following conditions:

   a. Spill at a dam must be reduced when:

      i. The average of the twelve highest hourly TDG measurements in the tailrace of the dam in a calendar day exceeds 120 percent of saturation; or

      ii. Instantaneous total dissolved gas levels exceed 125 percent of saturation in the tailrace of the dam, calculated as the average of the two highest hourly total dissolved gas measures in a calendar day.

   b. The DEQ Director may halt the voluntary spill program or require reductions in voluntary spill to reduce TDG levels if voluntary spill results in biological threshold exceedances when:

      i. More than 15 percent of salmonids examined show signs of gas bubble disease in their eyes or non-paired fins, or

      ii. More than five percent of salmonids examined show signs of gas bubble trauma in their eyes non-paired fins where more than 25 percent of the surface area is occluded by gas bubbles.

   c. Physical monitoring must occur and be adequate for implementing the requirements set out in this order.

9. The Corps must provide written notice to DEQ within 24 hours of any violations of the conditions in the modification as it relates to voluntary spill. Such notice must include actions proposed to reduce total dissolved gas levels or the reason(s) for no action.

10. No later than Jan. 31 following each year of this modification, the Corps must provide an annual written report to DEQ detailing the following:
    a. Flow and runoff descriptions for the spill season;
    b. Spill quantities and durations;
    c. Quantities of water spilled for fish versus spill for other reasons for each project;
    d. Data results from the physical and biological monitoring programs, including incidences of gas bubble trauma regardless of sample size;
    e. Evaluation of the relationship between observations of non-salmonid gas bubble trauma monitoring and exposure to elevated total dissolved gas levels;
    f. Description and results of any biological or physical studies of spillway structures and prototype fish passage devices to test spill at operational levels; and
    g. Implementation of gas abatement measures identified through adaptive management.

11. If requested, the Corps must report to the commission on any of the above matters or other matters relevant to this order.

12. The commission reserves the right to terminate or modify this order at any time.

For the purposes of Oregon's Order, ODEQ defines non-salmonid as including non-native species per their letter dated June 10, 2022 and email dated January 18, 2023. Gas bubble trauma monitoring in bi-state waters will include evaluation of non-native species in the population of non-salmonids to comply with Oregon's Order. WADOE's Rule Implementation Plan is unchanged and continues to require GBT evaluation of native non-salmonids.

The terminology that has been adopted to refer to the States' TDG Water Quality Standards (WQS) is the "gas cap." Gas cap spill is spill to the maximum level that meets, but does not exceed, the TDG criteria allowed under state law. In its implementation of spill for fish passage, the Corps will operate its fish passage projects in 2025 to the spill levels identified in the CRSO EIS ROD, 2020 CRS BiOps, and Appendix B of the USG Commitments as extended and modified, and in accordance with the States' TDG standards described above, including applying the different state calculation methodologies. When the standards vary or conflict, the Corps will apply the more stringent standard.

2.2. Spill Caps

The Corps' Reservoir Control Center (RCC) is responsible for daily management of spill operations responsive to changing conditions to manage TDG within all applicable State standards. To accomplish this, the RCC determines "spill caps" for each of the Corps' lower Columbia and lower Snake River projects daily throughout the fish passage spill season. Spill caps are the maximum spill level at each project that is estimated to meet, but not exceed, the gas cap.

To calculate spill caps, the Corps evaluates observed and forecasted variables that influence TDG levels, including: (1) environmental conditions (e.g., total flow, wind, ambient temperature, barometric pressure, and incoming TDG from upstream); and (2) project operations (e.g., spill level, spill pattern, tailwater elevation, proportion of flow through the turbines, and project configuration).

During spill for fish passage, the Corps reviews spill caps daily and adjusts as necessary to define the maximum spill level that maintains TDG within applicable State standards. Additional information about how the Corps will manage TDG is described in the 2025 Water Management Plan (see Appendix 4: TDG Management Plan)[7].

Higher spill than the target spill levels identified in Tables 3, 4, and 5 may occur due to high river flow that exceeds powerhouse hydraulic capacity or due to a lack of power demand (load). During periods when spill is greater than the spill cap due to lack of load conditions, the Corps manages excess TDG on a system-wide basis by incrementally increasing spill at projects

[7] The Water Management Plan (WMP) and associated appendices are updated annually. *See* https://public.crohms.org/tmt/documents/wmp/.

throughout the system in the order of priority defined in the Spill Priority List[8]. For this purpose, the RCC also defines spill rates to target multiple TDG levels in project tailraces that exceed the gas cap. The order of priority is coordinated with regional sovereigns in the Technical Management Team (TMT) to allocate spill to projects to best manage system TDG while also considering how best to protect fish and other aquatic biota.

3. SPILLWAY OPERATIONS AND SPILL LEVEL PRECISION

The Corps plans to achieve the target spill levels defined in Tables 3, 4, and 5 to the extent feasible; however, actual hourly spill levels at each dam may vary depending on the precision of the spillbay gate settings, real-time fluctuations in flow and/or project head, or automatic load following. At each project, spill is distributed across the spillway according to patterns defined in the project-specific chapters of the FPP[9] to provide favorable fish passage conditions.

Spillbay gates are opened to the settings identified in the FPP spill pattern table that correspond to the spill level that is closest to the target but may be slightly higher or lower than the target spill level. Due to these physical limitations in spill level precision, the observed hourly average spill level may vary ±2 kcfs when the target spill is a flow rate (e.g., kcfs) and ±1% when the target spill is a percentage. Not all projects are able to achieve this level of precision (e.g., Little Goose and Bonneville dams). Additional flexibility for balancing reserves (±5%) could occur at John Day Dam (spring and summer) and The Dalles Dam (summer) as identified in Appendix B of the USG Commitments. More information regarding project-specific spill precision limitations may be found in Section 9 below.

Snake River projects make spillbay gate setting changes as soon as feasible in response to target spill changes; however, there may be instances when spill level changes are delayed by up to 1 hour or more due to operation of the navigation locks.

4. MODIFICATIONS TO PLANNED OPERATIONS AND IN-SEASON MANAGEMENT

For planning purposes, the operations described in the 2025 FOP assume average runoff conditions. Actual runoff varies in magnitude and timing and observed river flow may be higher or lower than average at any time such that modifications to the planned operations may be required. To accommodate these varying runoff conditions and other routinely observed conditions as they arise, the Corps, in conjunction with the other Action Agencies, NMFS, and USFWS, coordinates with regional sovereigns on these conditions and other planned operations through the review of the 2025 FOP prior to spring spill operations (see section 4.1). The Corps responds in real-time to these routine conditions and planned operations by implementing adjustments as conditions require without additional coordination.

For unanticipated and unplanned conditions that are not pre-coordinated, the Corps responds as necessary to adjust to the condition, and when possible, will use the existing regional

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[8] Spill Priority List: https://public.crohms.org/tmt/documents/spill-priority/
[9] The FPP is coordinated annually with regional sovereigns through the FPOM. *See* https://public.crohms.org/tmt/documents/fpp/.

coordination process[10] to adaptively manage and make necessary in-season adjustments in spill and other fish operations (e.g., spill levels, spill caps, spill patterns, juvenile fish transportation, and pool operating ranges).

4.1. Conditions that May Require Adjustments to Planned Operations

Under certain conditions or circumstances, the Corps may be required to adjust spill higher or lower than the target spill level at one or more projects.

Planned and Routine Operational Adjustments:[11]

1. High flow conditions that exceed powerhouse hydraulic capacity and require spilling more than the target spill level.
2. Low flow conditions that require adjustments in spill level while maintaining project minimum generation requirements (see section 4.3.1. below).
3. Lack of power demand (load) resulting in increased spill.
4. Operational limitations, for example physical limitations of gate settings, spill patterns (see section 3), forebay elevation, and deadband[12].
5. Scheduled turbine unit and/or transmission outages that reduce powerhouse hydraulic capacity and require spilling more than the target spill level.* (see footnote 11)
6. Standard operations for transmission reliability (see section 4.4.1. below).*(see footnote 11)
7. Navigation safety concerns (see section 4.6. below).* (see footnote 11)
8. Transition periods between gas cap spill and lower spill rates (e.g., during performance standard spill blocks[13]) may result in actual hourly spill levels that are slightly higher or lower than targeted spill levels.

Non-routine or Unplanned Operational Adjustments:[14]

1. Contingency operations for transmission reliability (see section 4.4.2 below).

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[10] In-season adaptive management changes in spill levels could include adjustments that address unintended biological consequences caused by spill (e.g., adult passage delays), for the juvenile fish transportation program, for research activities for studies to evaluate fish passage facilities, survival, or other fish-related issues. Spill patterns and biological testing protocols that have not been coordinated to-date will be considered through the regional coordination process using Regional Forum subcommittees, which include the TMT, Studies Review Workgroup (SRWG), Fish Facility Design Review Work Group (FFDRWG), and FPOM.

[11] Planned and Routine Operational Adjustments are spill adjustments due to (1) conditions that occur routinely every year (e.g., high or low flow), or (2) planned operations (e.g., scheduled maintenance, transit of fish transport barge in the tailrace). These are considered pre-coordinated through regional sovereign review of the FOP and the FPP and are implemented by the Action Agencies as conditions require and without additional coordination through the regional forum processes. Spill adjustments due to routine or planned operations are included in the monthly FOP Implementation Report in the hourly spill and flow charts (plots), and conditions with an (*) are reported in the "Pre-Coordinated Operations" Table. The FPP (Appendix A) identifies actions with pre-coordinated dates.

[12] Deadbands occur when turbine outflow cannot achieve some flow ranges. When targeting spill as a percent of outflow, these deadbands will result in a spill percentage that is above or below the target percentage at certain outflows.

[13] "Performance standard" spill is a NMFS term and refers to spill levels intended to meet NMFS' performance standard testing, as described in the 2008 Biological Opinion and accompanying administrative record.

[14] Spill adjustments that occur due to non-routine or unplanned conditions or operations are implemented by the Action Agencies as conditions require and/or as coordinated with regional sovereigns through the in-season adaptive management process. Non-routine or Unplanned Operational Adjustments that affect spill levels are reported in the

2. Fish emergencies (e.g., high river temperatures that exceed levels safe for fish, adult fish passage blockages, actionable incidence rates of gas bubble trauma (GBT) incidence rates in either juvenile salmonids or non-salmonids[15], etc.).
3. Conditions related to project safety (e.g., erosion), health and human safety, navigation, or other unforeseen events that require spilling more or less than the target spill level.[16]
4. Other circumstances including human or programming error, unscheduled maintenance or outage, and other unanticipated events or emergencies.
5. In-season adjustments following adaptive management coordination through the existing regional coordination process (see section 4).

4.2. TMT Emergency Protocols

The Corps and the other Action Agencies operate the fourteen Columbia River System projects in emergency situations in accordance with the 2025 Emergency Protocols (WMP Appendix 1 – available online at https://public.crohms.org/tmt/documents/wmp/). This protocol identifies the process the Action Agencies, in coordination with NMFS and USFWS, use in the event of an emergency concerning project operations that impact planned fish protection measures. The emergency protocols also address the process for coordination with regional sovereigns.

4.3. Low Flow Operations

4.3.1. Minimum Generation

All lower Snake and lower Columbia River dams have a minimum generation requirement that has been established to support power system reliability (see section 4.4.). The Corps has identified minimum generation powerhouse outflow values derived from the lower limit of the ±1% peak efficiency operating range defined in the project-specific chapters of the FPP and from actual generation records (see Table 1). Values stated in Table 1 are approximate ranges that account for varying head or other small adjustments in turbine unit operation that may result in variations from the reported minimum generation flow and spill amount. Conditions that may result in minor variations include:

FOP Implementation Report Variance Table (and when warranted, a description may also be included in the Operational Adjustments section). When a Non-routine or Unplanned Operational Adjustment does not affect spill levels, information about this is provided in the Operational Adjustments section. If an adjustment continues into the next month, the adjustment is reported in the Pre-Coordinated Operations Table.

[15] *See* WAC 173-201A-200(1)(f)(ii)(B)(III), including WADOE's Rule Implementation Plan for Chapter 173-201A WAC Water Quality Standards for Surface Waters of the State of Washington (Publication 19-10-048; pages 7-9), and *Order Approving a Modification to the Oregon's Water Quality Standard for Total Dissolved Gas in the Columbia River Mainstem*, page 5, including clarifications from Oregon Department of Environmental Quality email dated 18 January 2023, RE: Request for Clarification of Spring Non-Salmonid Monitoring Requirement.

[16] When a generator requires repair, ongoing operations may require modification to prepare a turbine unit for the necessary maintenance without further damaging infrastructure or jeopardizing personnel safety. To safely install taillogs in a unit adjacent to the spillway, it may be necessary to cease spill through some spillbays for up to 6 or more hours during the installation of the physical barriers to isolate the area and subsequently dewater the draft tube environment. An alternate spill pattern for use during the maintenance period using the remaining spillbays will be coordinated through FPOM.

1. Varying reservoir elevation: as reservoirs fluctuate within the operating range, flow rates through the generating unit change.
2. Generating unit governor deadband: the governor controls the number of megawatts the unit should generate but cannot precisely control a unit flow; variations may be 1-2% or more of unit flow. These variations can affect minimum generation ranges in Table 1.
3. System disturbances: once a generator is online and connected to the grid, it responds to changes in system voltage and frequency. These changes may cause the unit to increase or decrease flow and generation within an hour. Individual units operate differently from each other and often have unit specific constraints.
4. Generation control systems regulate megawatt (MW) generation only, not flow through individual turbine units.

All of the lower Snake River powerhouses may be required to keep one generating unit[17] online at all times for power system reliability under low river flow conditions, which may result in a reduction of spill at that project if there is insufficient flow in the river. Generally, units 1–3 are the priority units for operation during the fish passage season for adult fish attraction flow to the fish ladders, but unit priority is also based on availability. During low river flow conditions, the Corps operates the lower Snake River and lower Columbia River projects to the unit priority order specified in the FPP and minimum generation ranges identified in Table 1.

[17] Two generating units may be necessary at Ice Harbor Dam during elevated air temperatures to meet transmission requirements.

Table 1.— Minimum generation flow ranges (kcfs) for turbine units at Corps hydropower projects on the lower Snake and lower Columbia rivers.[18]

Project	Turbine Unit	Minimum Generation Flow Range[A] (kcfs)
Lower Granite	1, 3	11.6 – 12.7
	2[B]	17.8 – 18.8
	4, 5, 6	13.8 – 14.9
Little Goose	1, 2, 3	11.8 – 12.3
	4, 5, 6	14.3 – 14.9
Lower Monumental	1, 2, 3	11.7 – 12.9
	4, 6	13.8 – 14.6
	5[B]	17.8 – 19.0
Ice Harbor	1[C]	Out of service
	2	12.1 – 14.1
	3	8.6 – 10.3
	4[B]	12.2 – 13.5
	5, 6[B]	12.5 – 14.1
McNary	N/A	50 – 60 (may increase up to 80 for reserves)[D]
John Day	N/A	50 – 60 (may increase up to 80 for reserves)[D]
The Dalles	N/A	50 – 60
Bonneville	N/A	30 – 40 (may increase to 60 for reserves)[D]

A. "Minimum Generation" is the minimum number of megawatts (MW) that must be generated at each project to support power system reliability. This table defines the resulting flow range (kcfs) through turbines, which is a function of power output (MW), turbine efficiency, and project head.
B. Lower Granite Unit 2, Lower Monumental Unit 5, and Ice Harbor units 4, 5, and 6 are restricted due to fixed-blade (non-adjustable) runners that are set at a fixed angle (non-adjustable). If a unit is restored to an adjustable-blade Kaplan in-season, the minimum generation range will revert to the lower 1% limit.
C. Ice Harbor Unit 1 is being rebuilt with an adjustable-blade runner design that reduces impacts to fish, scheduled for completion in 2026. At that time, testing will be performed to confirm the operating range.
D. Powerhouse outflows may increase for reserves up to 80 kcfs at McNary Dam during spring and summer months, up to 80 kcfs at John Day Dam during spring months and up to 60 kcfs at Bonneville Dam during spring months (without triggering reporting requirements described in Section 4.1). Increased powerhouse generation allowances will allow for additional generation for the purpose of providing real-time operators greater access to reserve capacity prior to requiring variance tracking or declarations of power system emergency. As needed, the higher ranges will be utilized for reserves under low flow conditions (e.g., minimum generation and spill the rest) and when flexibility elsewhere (e.g., Grand Coulee and Chief Joseph dams to carry and deploy reserves) has been maximized. Powerhouse flows exceeding 80 kcfs at McNary and John Day dams or 60 kcfs at Bonneville Dam for reserves within the Bonneville balancing authority area will be reported in the Pre-Coordinated Operations Table. Any other exceedances for reserves will be reported in the Variance Table in the monthly FOP Implementation Report (see section 10).

There may be situations when river flows are insufficient to maintain minimum generation in Table 1 and the target spill level identified in Tables 3, 4, and 5 every hour. Under these conditions, the lower Snake River projects operate one turbine unit at minimum generation and spill the remainder of outflow. The lower Columbia River projects also operate at minimum generation and pass the remaining outflow as spill down to minimum spill levels. Under low river flow conditions during spring spill operations, the Corps attempts to remain as close as

[18] The table is accurate as of March 2025 but may change in-season as coordinated through FPOM (see the FPP).

possible to spill target levels for either gas cap spill or other spill percentages or volumes, depending on which operation is targeted for a given hour. The inability to meet the target gas cap spill level due to low river flow does not preclude the ability of the Corps to target performance standard spill levels as specified in Table 4. Additionally, inflow provided by non-Federal projects upstream is often variable and uncertain, and in combination with low flow conditions, may result in instances where forebay elevations go outside of the restricted operating ranges for Snake River and Columbia projects described in Section 4.6.[19]

4.3.2. Navigation Lock Operation During Low Flows

At projects that have a target spill level that is a percentage of total outflow, emptying the navigation lock during low flow conditions may temporarily result in a reduced percentage of outflow that is reported as spill. During this time, the spill rate remains constant, but the spill reported as a percent of total outflow may be temporarily reduced below the target percentage. This occurs because the volume of water needed to empty the navigation lock during periods of low flow is a greater percentage of the total project outflow than during periods of higher flow.

4.4. Operations for Transmission System Reliability

In managing the fish passage spill operations, the Corps and Bonneville plan to allocate generation and spill at the eight Corps projects on the lower Columbia and Snake rivers in accordance with the 2025 FOP. Periodically, to ensure the reliability of the transmission system when system conditions warrant, it is necessary to increase or decrease the amount of water flowing through a project's turbines and spillbays at one or more of these projects.

Consistent with past practice, if any of the transmission system conditions listed below are present and can be alleviated by temporarily modifying generation levels at one or more federal projects, the Action Agencies adjust generation and spill levels to avoid the transmission system impact. These events could result in actual spill being temporarily higher or lower than the target fish passage spill level. Such events may occur coincident with the transmission system event or in subsequent hour(s) should the event impact water balance at a specific hydro project or river reach. The Corps and Bonneville work to restore conditions to support target spill operations as soon as practicable. These actions are taken to minimize the risk and/or scope of a transmission system emergency and are reported in the monthly FOP Implementation Report (see section 10 below).

4.4.1. Standard Operations for Transmission Reliability

Consistent with past practice, the Action Agencies manage the fourteen Columbia River System projects to be prepared to provide electric reliability support as follows:

[19] Lower Snake River projects operate within the minimum operating pool (MOP) range during fish passage season (Table 2).

1. Ensuring sufficient range of generation capability is available to provide the Bonneville balancing authority[20] area with contingency reserves required by North American Electric Reliability Corporation (NERC) reliability standards.[21]
2. Ensuring generation is available to increase or decrease to balance load and generation within the Bonneville balancing authority area to support reliability.
3. Ensuring enough generating units are online and have sufficient capability to increase or decrease generation to meet the Bonneville balancing authority area frequency response obligations, consistent with reliability standard requirements.
4. Bonneville must first meet its reserve obligations for system reliability.[22] When conditions result in an inability to meet the target spill levels defined in Tables 4 and 5, Bonneville will make best efforts to minimize the allocation of reserves (decremental, DEC and/or incremental, INC) on fish passage projects if a spill reduction would be required to allocate the reserves.
5. Ensuring that there is generation operating at projects in specific locations sufficient for arming for Remedial Action Schemes (RAS).[23] RAS allow the transmission system to automatically respond to unplanned events on the power system by immediately dropping or reducing generation at those specified locations.
6. Maintaining minimum generation levels (see Table 1) at generators in specific locations to maintain correct voltage levels on the power system to ensure reliability.
7. Maintaining enough generation units online in diverse locations on the electrical grid to ensure system stability through rotating inertia.

4.4.2. Contingency Operations for Transmission Reliability

If the routine reliability tools described above are insufficient to resolve the transmission condition, the Action Agencies implement the preemptive actions detailed in the Power System Emergency Action Plan (Attachment 1 to the TMT Emergency Protocols referenced in section 4.2 above) if time permits. Where necessary, the fourteen Columbia River System projects will be called upon to relieve the following conditions:

1. Increasing or decreasing generation at projects (redispatch) in specific geographic locations to relieve heavily loaded transmission lines if required by system conditions. This includes adjusting generation that flows over specific transmission facilities to keep flows over those paths within the requirements of NERC reliability standards.
2. Increasing or decreasing generation to ensure transmission system stability and/or reliable load service in local areas under specific system conditions. For example, increasing

[20] A balancing authority is the responsible entity that maintains load-interchange-generation balance within a Balancing Authority Area and supports interconnection frequency in real time. Balancing authority area is the collection of generation, transmission, and loads within the metered boundaries of the designated balancing authority. The balancing authority maintains load-resource balance within this area.
[21] The Federal Energy Regulatory Commission has certified the NERC as the Electric Reliability Organization responsible for establishing and enforcing national reliability standards.
[22] For example, generators may be required to maintain generation levels above minimum generation to provide sufficient capability to reduce generation.
[23] Remedial Action Schemes are sets of automatic control circuits that switch various types of power system components on or off in response to disturbances on the interconnected transmission system.

generation at Ice Harbor Dam to support transmission stability, including providing load service to the Tri-Cities area of Washington, when system conditions require.
3. Responding to unanticipated significant events, including NERC Energy Emergency Alerts or other system emergencies, consistent with the Power System Emergency Action Plan included as Attachment 1 to the TMT Emergency Protocols.
4. Other unanticipated significant events (e.g., fires, earthquakes, etc.).

These actions are implemented consistent with the TMT Emergency Protocols (see section 4.2 above).

4.5. Turbine Unit Testing for Maintenance

Turbine units may be operationally tested prior to maintenance and prior to return to service by running the unit at speed no load, various loads within the ±1% of peak efficiency range, and, if necessary, up to full load, to allow for measurements and testing. Testing of a unit under maintenance is in addition to a unit operating at minimum generation required for power system reliability. Testing may deviate from unit operating priorities specified in FPP Chapters 2-9 and may use water that would otherwise be used for spill if the unit operating for reliability is at the bottom of the ±1% of peak efficiency range. Water is used from the powerhouse outflow allocation if possible, and water diverted from spill for operational testing will be minimized. The Corps coordinates this testing with the region through FPOM. Unit outages for required maintenance are described in FPP Appendix A. Maintenance dates are subject to change.

4.6. Navigation Safety and Minimum Tailwater Elevations

Short-term adjustments in spill or minimum operating pool (MOP) elevations may be required at any of the fish passage projects to address navigation safety concerns.[24] This may include changes in spill patterns, reductions in spill, short-term spill curtailment, or operating above MOP. Adjustments to MOP may also be required to meet minimum tailwater elevations (Table 2). Current spill operations for fish passage result in complex downstream hydraulics that cause large fluctuations in tailwater elevations. The 2020 BiOps describe MOP at the lower Snake River projects as a 1.5-foot range above the minimum forebay elevation (Table 2). To clearly communicate the implementation of this operation, the term "MOP" will refer to the 1.5-foot operating range above the minimum forebay elevation at the lower Snake River projects (i.e., "MOP" is a 1.5-foot operating range).

The Corps will operate Lower Granite Dam at MOP with a 1.5-foot forebay operating range and a 1.0-foot range to the extent possible (referred to operationally as a "soft constraint") from April 3 until August 31, unless adjusted on occasion to meet authorized project purposes, primarily navigation, except as noted below.[25] Little Goose, Lower Monumental and Ice Harbor dams will operate at MOP with a 1.5-foot forebay operating range and a 1.0-foot range soft constraint to

[24] The Corps conducts annual surveys to assess sedimentation in the reservoirs and under certain conditions. To ensure safe navigation, there may be a need to operate the pools above the MOP range.
[25] The Corps conducts a bathymetric survey of the federal navigation channel annually to assure a 14-foot depth is maintained in the federal navigation channel. With the dredging completed in winter 2022/2023, Lower Granite will operate in the normal MOP range (733.0-734.5 feet) from April 3 until August 31 (and within a 1.0-foot soft constraint range to the extent possible).

the extent possible from April 3 until August 14, unless adjusted on occasion to meet authorized project purposes, primarily navigation, except as noted below.

Table 2.— Normal and minimum operating pool (MOP) elevation ranges and minimum tailwater elevations for lower Snake River projects. [A]

Project	Normal Operating Elevation Range (ft)[B]		MOP Elevation Range (ft)[C]		Project Tailwater (ft)
	Minimum	Maximum	Minimum	Maximum	Minimum
Lower Granite	733.0	738.0	733.0	734.5	633.0
Little Goose	633.0	638.0	633.0	634.5	537.0
Lower Monumental	537.0	540.0	537.0	538.5	437.0
Ice Harbor	437.0	440.0	437.0	438.5	337.0

A. Elevations provided in feet above mean sea level (NGVD29).
B. August 15 – April 2, except at Lower Granite (September 1-April 2).
C. April 3 – August 14, except at Lower Granite (April 3 – August 31). Projects will be operated within a 1.0-foot range to the extent possible (referred to operationally as a "soft constraint").

Potential in-season adjustments to MOP, if necessary, will be an expanded forebay operating range (Expanded MOP) or raised minimum forebay elevation (Raised MOP), as described below.

Expanded MOP: If the 1.5-foot MOP range is insufficient to maintain navigation safety, the range is expanded (e.g., to 2 feet). For instance, some flow conditions may require a 2-foot forebay operating range at Ice Harbor to provide safe conditions for barge traffic at the navigation lock exit. These adjustments may be necessary for both commercial traffic and fish transport barges. Using Ice Harbor as an example, this type of adjustment would be described as "2-foot expanded MOP (437.0-439.0 feet)". Additionally, large within day fluctuations between gas cap spill and spill percentages or prescribed volumes may cause operational challenges in meeting MOP and an expanded MOP may be necessary, especially when combined with restricted turbine units that are not able to operate in the full ±1 percent range.

Raised MOP: If the minimum forebay elevation is insufficient to maintain navigation safety or meet project minimum tailwater elevations, the 1.5-foot MOP range is raised as necessary. Adjustments in MOP operations have been necessary at the lower Snake River projects, typically during lower flow conditions. For instance, low flows in combination with fish passage spill operations may impact reservoir elevations and cause dips below project minimum tailwater elevations or inadequate navigation depths. Using Little Goose as an example, this type of adjustment would be described as "1.5-foot raised MOP (634.5-636.0 feet)".

Spill Adjustments: High spill levels may create unsafe hydraulic conditions for commercial, non-commercial, and fish transportation barges entering and exiting the tailrace and/or while moored at the fish transport loading facility. Under these conditions, spill may be reduced temporarily as necessary to maintain safe navigation conditions for commercial, non-commercial, or fish transportation barges, which may result in temporarily filling the pool above the MOP range, depending on river flow.

5. JUVENILE FISH TRANSPORTATION PROGRAM

The best available information will be considered in the Corps' implementation of the juvenile fish transportation program operations at the Snake River collector projects in 2025. Should regional sovereigns recommend adjustments in transportation start dates that differ from those stated herein, the Corps uses the existing regional adaptive management process to reconcile recommended operational adjustments.

The following describes the proposed transportation operations for the lower Snake River projects. Detailed descriptions of project and transport facility operations to implement the juvenile fish transportation program are contained in the FPP Appendix B.

5.1. Lower Snake River Dams – Transport Operation and Timing

Transportation will be initiated at Lower Granite, Little Goose and Lower Monumental dams on April 24 (collection starting on April 23) or as coordinated through the TMT and the RIOG but begin no later than May 1. Transport begins the following day after fish collection and collected juvenile fish will be transported from each facility on a daily or every-other-day basis (depending on the number of fish) throughout the migration season. Transportation of spring migrants ends on June 20. Truck transportation of summer migrants at Lower Granite and Little Goose resumes on August 1 with allowance for TMT adaptive management adjustments and continues through October 31. Transportation operations are carried out at each project in accordance with relevant FPP operating criteria. Transportation and spill operations may be adjusted due to research, conditions at fish collection facilities (e.g., overcrowding or temperature extremes), or through the adaptive management process with FPOM and/or TMT (e.g., to respond to expected environmental conditions, to respond to recent transport vs in-river research results, to better match juvenile outmigration, or to achieve/maintain spill targets).

5.2. Transport Research – Seasonal Effects of Transport

An ongoing annual study will be conducted again in 2025 to determine seasonal effects of transporting fish from the Snake River to optimize a transportation strategy. Fish will be collected for this study at Lower Granite starting on April 14, with marking beginning on April 15.

Depending on the number of fish available, fish will be collected 1-2 days each week with tagging occurring on the day following collection. A barge will leave on Thursday (17 April) morning with all fish collected during the previous 1-2 days (excluding fish tagged for in-river survival, which will be released into Lower Granite Dam tailrace). If necessary to achieve the proper loading density, additional fish will be collected on 16 April (but not tagged). By barging all fish (minus the in-river group) during 1 to 3 days of collection, barge densities are expected to be maintained similar to what would occur under normal transport operations at that time of year. This pattern will occur the week preceding general transportation and will be incorporated into general transportation once that operation begins. The desired transported sample size is 6,000 wild Chinook, 4,000-6,000 wild steelhead, and 4,000-6,000 hatchery steelhead weekly for approximately five to six weeks.

6. FALL/WINTER SURFACE SPILL OPERATIONS

Surface spill operations in March–April and September–November (referred to in Appendix B of the USG Commitments Document as "Fall/Winter Spill Operations") will occur during the dates and times defined below in Table 3. Surface spill will occur via the project's spillway weir (RSW, TSW, or ASW[26]), except at The Dalles and Bonneville dams which do not have a spillway weir and will instead operate non-spillway surface passage routes as defined in Table 3.

Table 3.— Fall/Winter Surface Spill Operations.[A]

Project	Dates	Hours	Notes
LWG, LGS, LMN, IHR, MCN	March 1 – March 20	4 hours/day in the morning, 7 days/week	LGS ASW in high crest (~7 kcfs). MCN TSW in spillbay 20.
	March 21 – April 2 (Snake projects) / April 9 (MCN)	24 hours/day, 7 days/week	
	September 1 – November 15	4 hours/day in the morning, 7 days/week	
JDA	March 21 – April 9	24 hours/day, 7 days/week	Opening the JDA TSW requires a crew and crane and must be done during daylight hours. On March 21, an equivalent spill rate (~10 kcfs) will occur via the non-TSW pattern from 0001 hours until the TSW in spillbay 19 is opened in the morning as early as possible.
TDA Sluiceway	March 1 – December 15	24 hours/day, 7 days/week	TDA sluiceway is a non-spillway surface passage route. See FPP Chapter 3 for operating criteria.
BON B2CC	March 1–8	0600-1000 daily	BON PH2 corner collector (B2CC) is a non-spillway surface passage route. See FPP Chapter 2 for operating criteria.
	March 9–25	0600-1000, 1600-2000 daily	
	March 26 – August 31	24 hours/day, 7 days/week	
BON Sluiceway	Year-round	24 hours/day, 7 days/week	BON PH1 sluiceway is a non-spillway surface passage route. See FPP Chapter 2 for operating criteria.

A. Spill may be temporarily reduced below the FOP target spill level at any project if necessary to ensure navigation safety or transmission reliability, or to avoid exceeding State TDG standards.

7. SPRING FISH PASSAGE SPILL OPERATIONS

Spring spill operations occur April 3–June 20 at the four lower Snake River projects, and April 10–June 15 at the four lower Columbia River projects. The Corps initiates spill at 0001 hours, or shortly after midnight, at each of the projects on the start date. Target spill levels for spring 2025 at each project are defined in Table 4. If deleterious impacts of the proposed spill operations are observed in-season, existing adaptive management processes may be employed to address the

[26] Depending on their design, spillway weirs are referred to as either "Removable" (RSW–applies to LWG, LMN, IHR), "Adjustable" (ASW–applies to LGS), or "Top" (TSW–applies to MCN and JDA).

cause of the impacts. Spill may be temporarily reduced at any project to ensure navigation safety or transmission reliability. In order to operate consistently with state water quality standards, spill may also be reduced if observed GBT levels exceed those identified in state water quality standards (*See* WASH. ADMIN. CODE § 173-201A-200(l)(f)(ii)(B)(III) and *Order Approving a Modification to Oregon's Water Quality Standard for Total Dissolved Gas in the Columbia River Mainstem*, page 5).

Spill up to the 125% gas cap is spill to the maximum level that meets, but does not exceed, the TDG criteria allowed under state laws. This includes a criterion for not exceeding 126% TDG for the average of the two greatest hourly values within a day.

Table 4.— Summary of 2025 spring target spill levels at lower Snake River (April 3 – June 20) and lower Columbia River (April 10 – June 15) projects.

PROJECT	SPRING SPILL DATES	SPRING SPILL OPERATION
Lower Granite [A, C]	April 3 - June 20	24 hours/day: 125% Gas Cap
Little Goose [B, C]	April 3 – June 20	125% Gas Cap 24 hours/day (until adult criteria met) *then* 16 hours/day: 125% Gas Cap; 8 hours/day: 30% of outflow (Performance Standard)
Lower Monumental [A]	April 3 - June 20	24 hours/day: 125% Gas Cap
Ice Harbor	April 3 – June 20	24 hours/day: 125% Gas Cap
McNary	April 10 – June 15	24 hours/day: 125% Gas Cap
John Day [D]	April 10 – June 15	Daytime hours: 40% of outflow; Nighttime hours: 125% Gas Cap
The Dalles [E]	April 10 – June 15	24 hours/day: 40% of outflow (Performance Standard)
Bonneville [F]	April 10 – June 15	24 hours/day: 125% Gas Cap

A. Lower Granite and Lower Monumental Adult Delay Criteria – See Section 7.1.
B. Little Goose Adult Criteria –Within 1 business day of when the earliest of the following conditions occurs: (1) a cumulative total of 25 adult spring Chinook salmon (not including jacks) pass Lower Monumental Dam; or (2) a cumulative total of 50 adult spring Chinook salmon (not including jacks) pass Ice Harbor Dam; or (3) April 24, 2025, the Corps will implement performance standard spill at Little Goose Dam for 8 consecutive AM hours (April 3–15 starting at 0500 hours; April 16–June 20 starting at 0400 hours) to target hours of peak adult passage. If lack of load conditions preclude the implementation of performance standard spill during the targeted periods, performance standard spill will begin as soon as practicable during AM hours and continue for up to 8 consecutive hours. If a second block is needed, it will start as soon as load conditions allow, continue for at least two consecutive hours, and conclude no later than 2000.
C. During periods of high river flow that exceeds powerhouse hydraulic capacity, implementing 8 consecutive hours of spill as described in Footnotes A and B may result in storing additional inflow in the forebay above MOP. If it is necessary to pond water to achieve the 8-hour block of spill during high inflow, water stored above MOP should be drafted out over the remaining hours by increasing spill to pass inflow from 1200-1600 hours, then increasing spill as necessary from 1600-0400 to draft the pool back to MOP. If it is forecasted that the drafting spill will result in exceeding 130% TDG in the tailrace, all 16 hours will be used to return the pool to MOP. In lack of load conditions performance standard spill blocks will be prioritized at Little Goose, Lower Monumental, and Lower Granite dams, in that order.
D. John Day Dam – Daytime hours are defined in FPP Chapter 4, Table JDA-5. Daytime hourly spill target of 40% river flows with ±5% flexibility in river flow for balancing reserves, consistent with current target spill level calculations.

E. The Dalles Dam –TDG in The Dalles tailrace may fluctuate up to 125% prior to reducing spill at upstream projects or reducing spill at The Dalles below 40%. Maintain 40% spill for 24 hours at The Dalles and reduce John Day spill below the 125% TDG spill cap as needed for TDG management. Spill above 40%, up to 125% TDG, may occur for TDG management or for carrying reserves.
F. Bonneville Dam – Spill for fish passage should not exceed 150 kcfs due to erosion concerns.

7.1. Adult Migration Delay Protocol for Spring Spill Operations at Lower Granite and Lower Monumental Dams

Lower Granite and/or Lower Monumental daytime spill levels will be decreased to 40% of project outflow for 8 hours per day during daytime hours (targeted start time between 0400-0800 if feasible) when adult delay or passage issues are observed at both/either of these projects. An adult delay or passage issue occurs when the following three criteria are met: (1) *fewer than* 50% of the single departure event per tag ID of PIT-tagged adult spring/summer Snake River Chinook detected at the downstream project (i.e., Ice Harbor or Little Goose dams) arrive at the upstream project (i.e., Lower Monumental or Lower Granite dams) within 3 days and this pattern persists for 4 consecutive days,[27] (2) a running 3-day minimum of 7 PIT-tagged adult spring/summer Snake River Chinook are detected at the downstream projects,[28] and (3) if the upstream dam's average outflow was below 160 kcfs each day of the delay. If all three criteria are met, the Corps will implement a 40% daytime spill operation (adult daytime spill operation) for 8 hours per day during daytime hours (targeted start time between 0400-0800 if feasible) on the next calendar day and continue for 3 consecutive days. Based on the availability of information on the three criteria, the adult 40% daytime spill operation may begin as early as day 5 and no later than day 6. Consistent with past operations to reduce spill at Little Goose Dam, if lack of load conditions preclude the implementation of 40% spill to begin between 0400-0800, reduced spill will occur as soon as practicable during morning hours and continue for up to 8 consecutive hours. If 8 hours of consecutive spill at 40% was not feasible, a second block will start as soon as load conditions allow, continue for at least two consecutive hours, and will conclude no later than 2000 (see Table 4, footnote B).

Assuming *greater than* 50% of the single departure event per tag ID of PIT-tagged adults arrive at the upstream project by day 3 then standard operations (125% TDG spill 24/7) would be reinstated the calendar day after information becomes available, as early as day 4 and no later than day 5. If greater than 50% of the daily cohort does NOT arrive at the upstream project by day 3 and project average flow was below 160 kcfs, adult daytime spill operations would continue an additional day and would be evaluated again the following day as previously described. This would continue until the adult delay or passage issue has been resolved and the standard operations can be reinstated as described in Table 4.

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[27] The return to 125% TDG spill 24/7 will be triggered if 50% or more of the running 3-day cohort for the most recent day (e.g., day 3 of adult daytime spill) is detected at the upstream dam. The agencies will use Columbia River DART's Reach Distribution and Delay for PIT Tag Adult Returns tool for this purpose.
[28] The agencies will use the current Columbia River DART's Reach Distribution and Delay for PIT Tag Adult Returns tool ("Running 3-day DART tool") to determine if criteria one and two have been met. See top panel, in-season graphics of Cumulative Arrival Percent by Days in Route to Lower Granite or Lower Monumental dams. https://www.cbr.washington.edu/dart/query/pitadult_reachdist

The TMT may consider in-season deviations from these criteria if unforeseen factors are reasonably expected to cause substantial delay (e.g., lack of load conditions, priority turbine unit outages, etc.) and the Fish Passage Operations and Maintenance (FPOM) Coordination Team may consider refinements to these triggers following each spring spill season.

8. SUMMER FISH PASSAGE SPILL OPERATIONS

Summer spill operations occur June 21–August 31 at the four lower Snake River projects, and June 16–August 31 at the four lower Columbia River projects. The Corps initiates spill at 0001 hours, or shortly after midnight, at each of the projects on the start date. Target spill levels for summer 2025 at each project are defined in Table 5. At the Snake River Projects spill may ranges up to ±1 kcfs during the summer spill operation from August 1 – August 31.

Table 5.— Summary of 2025 summer target spill levels at lower Snake River and lower Columbia River projects.

PROJECT	EARLY SUMMER SPILL[A] (June 21/16 – July 31) (24 hrs/day)	LATE SUMMER SPILL[A] (August 1 – August 31) (24 hrs/day)
Lower Granite [B]	18 kcfs	RSW flow (as river flow allows)
Little Goose [B, C]	30%	ASW flow or 7 kcfs
Lower Monumental [B, D]	17 kcfs	RSW flow or 8 kcfs
Ice Harbor [B, E]	30%	RSW flow or 9 kcfs
McNary [F]	57%	2 TSWs flow or 20 kcfs
John Day	35% [G]	2 TSWs flow [H] or 20 kcfs
The Dalles	40% [G]	30% [G]
Bonneville	95 kcfs	50 kcfs

A. Spill may be temporarily reduced below the FOP target summer spill level at any project if necessary to ensure navigation safety or transmission reliability, or to avoid exceeding State TDG standards.
B. Late summer spill August 1-August 31 will be through the spillway weir or a constant spill rate through conventional spillbays using the appropriate FPP spill pattern. The spillway weir spill rate is a function of forebay elevation (as pool elevation increases, more water is spilled over the weir), as defined in the FPP. The spillway weirs will be operated per FPP criteria and closed when low flow criteria are met. When the spillway weir is closed, the spill target will transition to a constant spill rate through conventional spillbays and will not vary with a fluctuating forebay elevation.
C. Flow corresponds to the Little Goose ASW high crest elevation as adjusted relative to the forebay operating range (see FPP Chapter 8, section 2.3.2.7).
D. Flow corresponds to a Lower Monumental forebay elevation of 538.5 feet, the mid-point of the forebay range from 537-540 feet.
E. Flow corresponds to an Ice Harbor forebay elevation of 438.5 feet, the mid-point of the forebay range from 437-440 feet.
F. From June 16-July 31, McNary will adjust spill once a day to 57% of the previous day's average project outflow. The intent is to reduce the frequency of spillgate changes while implementing a more uniform pattern to the extent it can be done safely (see FPP Chapter 5, section 2.2.1.1).
G. Hourly spill percentage target of river flow with ±5% flexibility of river flow for balancing reserves, consistent with current target spill level calculations.
H. John Day will also spill from bay 2 open 1 stop (approximately 1.6 kcfs) during daylight hours when spill is through the TSWs only to maintain attraction flow to the north adult ladder, per FPP Chapter 4 (JDA), section 2.2.3.

9. PROJECT-SPECIFIC OPERATIONS

The following sections describe 2025 spill operations for each project. The Corps implements established spill patterns for all projects as described in the FPP. Additional information regarding spill precision outside these dates may be found in Section 3 above.

9.1. Lower Granite Dam

9.1.1. Fall/Winter Surface Spill (Table 3). The Lower Granite RSW spill rate will increase with increasing forebay elevation, from approximately 5.6 kcfs at the bottom of the normal forebay operating range up to 11.4 kcfs at the top of the range (see FPP Chapter 9, section 2.3.2.6).

- March 1–20: RSW spill 4 hours/day in the morning, 7 days/week.
- March 21 – April 2: RSW spill 24 hours/day, 7 days/week.
- September 1 – November 15: RSW spill 4 hours/day in the morning, 7 days/week.

9.1.2. Spring Spill (Table 4): 125% gas cap (see Section 2.1), 24 hours/day, April 3–June 20. If adult passage delay is observed (see Section 7.1), then 125% gas cap, 16 hours/day, and 40% of outflow, 8 hours/day.

9.1.3. Summer Spill (Table 5):

- June 21–July 31: 18 kcfs, 24 hours/day.
- August 1–31: RSW spill, 24 hours/day.

9.1.4. Operational Considerations: During low flow when spill is less than 15 kcfs and the RSW is open, Lower Granite will transition to alternate spill patterns defined in FPP Table LWG-7-ALT if needed to maintain the tailwater elevation at no lower than 633 feet. The project will switch to these alternate patterns to avoid or minimize the need to raise the Little Goose forebay operating range to keep from dropping below the Lower Granite minimum tailwater elevation.

9.2. Little Goose Dam

9.2.1. Fall/Winter Surface Spill (Table 3). The Little Goose ASW will be adjusted relative to forebay up to once per day to maintain a "high crest" elevation and a minimum of 7 kcfs spill (see FPP Chapter 8, section 2.3.2.7).

- March 1–20: ASW high crest 4 hours/day in the morning, 7 days/week.
- March 21 – April 2: ASW high crest 24 hours/day, 7 days/week.
- September 1 – November 15: ASW high crest 4 hours/day in the morning, 7 days/week.

9.2.2. Spring Spill (Table 4): 125% gas cap (see section 2.1), 24 hours/day, April 3 until adult criteria are met, then 125% gas cap, 16 hours/day, and 30% of outflow (performance standard) 8 hours/day, through June 20 (Table 3, footnote B).

9.2.3. Summer Spill (Table 5):

- June 21–July 31: 30% of outflow, 24 hours/day (except when adjusted to a constant spill level during low flows, as described in Operational Considerations below).
- August 1–31: ASW spill or approximately 7 kcfs, 24 hours/day.

9.2.4. Operational Considerations:

- When the ASW is closed and project outflow is less than or equal to 38 kcfs, actual hourly average spill levels at Little Goose may range up to ±4% according to the spill patterns in FPP Chapter 8 Table LGS-11.
- During low flow conditions at Little Goose, spill may exceed the target percentage if the ASW is in service, which restricts the project to a fixed minimum spill level (i.e., spill cannot be reduced below the spill rate through the ASW, which may result in spilling more than the target percentage at lower outflows).
- During the 30% spill operation when project outflows are ≤ 32 kcfs, the spill operation will transition from 30% to a constant spill rate of approximately 7-11 kcfs to help stabilize project outflow, meet Lower Monumental target spill levels, and maintain MOP elevation at Little Goose. The constant spill level will be based on the previous day's average total project outflow, as follows: 11 kcfs when total outflow is 28.0 to 32.0 kcfs, 9 kcfs when total outflow is 24.0 to 27.9 kcfs, and 7 kcfs when total outflow is ≤ 23.9 kcfs. Actual spill may range up to ±1 kcfs from the target spill level. Spill changes will be made by 0300 each day.

9.3. Lower Monumental Dam

9.3.1. Fall/Winter Surface Spill (Table 3). The Lower Monumental RSW spill rate will increase with increasing forebay elevation, from approximately 6.7 kcfs at the bottom of the forebay operating range up to 9.5 kcfs at the top of the range (see FPP Chapter 7, section 2.3.2.6).

- March 1–20: RSW spill 4 hours/day in the morning, 7 days/week.
- March 21 – April 2: RSW spill 24 hours/day, 7 days/week.
- September 1 – November 15: RSW spill 4 hours/day in the morning, 7 days/week.

9.3.2. Spring Spill (Table 4): 125% gas cap (section 2.1), 24 hours/day, April 3–June 20. If adult passage delay is observed (Section 7.1), then 125% gas cap, 16 hours/day, and 40% of outflow 8 hours/day. Spring spill will occur using the uniform pattern, except during low

flows (spill below 30 kcfs) when the bulk pattern will be used to avoid small gate openings that could impact fish.

9.3.3. Summer Spill (Table 5):

- June 21–July 31: 17 kcfs (bulk pattern), 24 hours/day.
- August 1–31: RSW spill or approximately 8 kcfs, 24 hours/day.

9.3.4. Operational Considerations: Transit of the juvenile fish barge across the Lower Monumental tailrace, docking, and departure from the collection facility, may require a reduction in spill below the target spill level for safety concerns. The towboat captain may request spill be reduced or eliminated during transit. During juvenile fish barge loading operations, spill is typically reduced to 15 kcfs using the bulk pattern, but can be reduced further, if necessary, for safety reasons. Barge loading duration can be up to 3.5 hours. Reducing spill may cause the Lower Monumental pool to briefly operate outside of MOP elevations.[29]

9.4. Ice Harbor Dam

9.4.1. Fall/Winter Surface Spill (Table 3). The Ice Harbor RSW spill rate will increase with increasing forebay elevation, from approximately 7.1 kcfs at the bottom of the forebay operating range up to 10.4 kcfs at the top of the range (see FPP Chapter 6, section 2.3.2.6).

- March 1–20: RSW spill 4 hours/day in the morning, 7 days/week.
- March 21 – April 2: RSW spill 24 hours/day, 7 days/week.
- September 1 – November 15: RSW spill 4 hours/day in the morning, 7 days/week.

9.4.2. Spring Spill (Table 4): 125% gas cap (see section 2.1), 24 hours/day, April 3–June 20.

9.4.3. Summer Spill (Table 5):

- June 21–July 31: 30%, 24 hours/day.
- August 1–31: RSW spill or approximately 9 kcfs, 24 hours/day.

9.4.4. Operational Considerations:

- When the RSW is open, the minimum project spill level is fixed at approximately 7.1-8.7 kcfs, depending on forebay elevation (i.e., spill cannot be reduced below the fixed volume through the RSW). This operational limitation results in spilling more

[29] With spill levels in spring 2025 targeting the gas cap for at least 16 hours/day, reducing spill at Lower Monumental for long durations could pose problems for staying within MOP at Ice Harbor Dam, the next downstream project.

than 30% when total outflow drops below approximately 28 kcfs. Per FPP section 2.3.2.7, the RSW is closed when day average outflow is below 30 kcfs and forecasted to stay below 30 kcfs for at least 3 days. However, outflow may drop below 28 kcfs on an hourly basis while the RSW is still open, resulting in spill greater than 30% for those hours.

- Currently, all but one of the five available Ice Harbor turbines have runner blades that are locked at a set angle (non-adjustable) and a smaller operating range (also referred to as "fixed-blade" or "locked-blade" units). Only Unit 3 has adjustable blades. As a result, turbine outflow cannot achieve some flow ranges, referred to as deadbands. When targeting spill as a percent of outflow, these deadbands will result in a spill percentage that is above or below the target percentage at certain outflows. Unit 1 is currently out of service until 2026 to install a new adjustable-blade runner design.

9.5. McNary Dam

9.5.1. Fall/Winter Surface Spill (Table 3). The McNary TSW spill rate will increase with increasing forebay elevation, from approximately 8 kcfs at the bottom of the normal forebay operating range up to 11 kcfs at the top of the range.

- March 1–20: Spillbay 20 TSW 4 hours/day in the morning, 7 days/week.
- March 21 – April 9: Spillbay 20 TSW 24 hours/day, 7 days/week.
- September 1 – November 15: Spillbay 20 TSW 4 hours/day in the morning, 7 days/week.

9.5.2. Spring Spill (Table 4): 125% gas cap (see section 2.1), 24 hours/day, April 10–June 15.

9.5.3. Summer Spill (Table 5):

- June 16–July 31: 57% of the previous day's average outflow, 24 hours/day. Spill changes will be made by 0300 each day.
- August 1–31: Two TSWs spill or 20 kcfs, 24 hours/day.

9.5.4. Operational Considerations:

- Currently, McNary spillbays are restricted due to hoists and cranes that need replacement. As a result, McNary will implement modified spill patterns. For more information, see FPP Chapter 5 (MCN), section 2.2.
- Currently, McNary Dam turbine units 5 and 6 have runner blades that are locked at a set angle (non-adjustable). As a result, the units are restricted to a very narrow ±1% operating range of approximately 10-12 kcfs (see FPP Chapter 5 Table MCN-

6-A) and there may instances when the unit is unable to stay within this restricted range.

9.6. John Day Dam

9.6.1. Fall/Winter Surface Spill (Table 3).

- March 21 – April 9: Spillbay 19 TSW spill 24 hours/day, 7 days/week.
- Opening the TSWs at John Day Dam requires a crew and gantry crane and must be done during daylight hours as weather allows. On March 21, spill will occur at an equivalent rate (approximately 10 kcfs) with the non-TSW pattern in FPP Table JDA-9 from 0001 hours until the TSW is opened in the morning.

9.6.2. Spring Spill (Table 4): 40% of outflow daytime and 125% gas cap nighttime, April 10–June 15, with priority to maintain 40% spill 24 hours/day at The Dalles Dam as needed for TDG management. Daytime hours are defined in FPP Chapter 4, Table JDA-5. A crew will install the TSW in spillbay 18 on the first day of spring spill as early as possible during daylight hours (see TSW operating criteria in FPP Chapter 4, section 2.3.2.4).

- Daytime 40% of outflow with ±5% flexibility of river flows for balancing reserves, consistent with current target spill level calculations. Deviations outside of ±5% of river flow for reserves within the Bonneville balancing authority area will be reported in the Pre-Coordinated Operations Table in the monthly FOP implementation report (see section 10). Any other exceedances for reserves will be reported in the Variance Table in the monthly FOP implementation report.

9.6.3. Summer Spill (Table 5):

- June 16–July 31: 35% of outflow, 24 hours/day with ±5% flexibility for balancing reserves, consistent with current target spill level calculations. Deviations outside of ±5% of river flows for reserves within the Bonneville balancing authority area will be reported in the Pre-Coordinated Operations Table in the monthly FOP Implementation Report (see section 10). Any other exceedances for reserves will be reported in the Variance Table in the monthly FOP Implementation Report.
- August 1–31: Two TSWs or 20 kcfs, 24 hours/day. A crew will close both TSWs on the last normal workday of summer spill, Thursday, August 28, 2025, as late in the day as possible. Spill will be maintained at an equivalent rate of 20 kcfs through midnight on August 31 using the spill patterns with no TSWs (see TSW operating criteria in FPP Chapter 4, section 2.3.2.4).

9.6.4 Operational Considerations:

- Currently, turbine units 2, 3, 8, 9, 10, 11, and 13 at John Day have runner blades that are locked at a set angle (non-adjustable) and a smaller operating range (see FPP Chapter 4 Table JDA-7-A). As a result, the turbines have a restricted operating

range of approximately 17-19 kcfs and may not be able to stay within the narrow 1% turbine band associated with it.

- See the WMP sections 6.11.1.4 and Tables 2 and 5 and Section 6.11.1.3 for discussion of springtime pool elevations to dissuade nesting of Caspian terns at Blalock Island. This operation is also described in the FPP Appendix A. This higher forebay operation will increase the flow rate over the TSWs and may change tailrace flow patterns.

9.7. The Dalles

9.7.1. Fall/Winter Surface Spill (Table 3): The ice & trash sluiceway (ITS) is a powerhouse (non-spillway) surface passage route and will operate March 1–December 15, 24 hours/day, pursuant to criteria in FPP Chapter 3.

9.7.2. Spring Spill (Table 4): 40% of outflow, 24 hours/day, April 10–June 15. Maintain 40% spill 24 hours/day at The Dalles Dam and reduce John Day Dam TDG spill cap as needed for TDG management.

9.7.3. Summer Spill (Table 5):

- June 16–July 31: 40% of outflow, 24 hours/day, with ±5% flexibility for balancing reserves, consistent with current target spill level calculations. Deviations outside of ±5% of river flow for reserves within the Bonneville balancing authority area will be reported in the Pre-Coordinated Operations Table in the monthly FOP Implementation Report (see section 10). Any other exceedances for reserves will be reported in the Variance Table in the monthly FOP Implementation Report.

- August 1–31: 30% of outflow, 24 hours/day, with ±5% flexibility for balancing reserves, consistent with current target spill level calculations. Deviations outside of ±5% of river flow for reserves within the Bonneville balancing authority area will be reported in the Pre-Coordinated Operations Table in the monthly FOP Implementation Report (see section 10). Any other exceedances will be reported in the Variance Table in the monthly FOP Implementation Report.

9.7.4. Operational Considerations:

- Spill bays 9[30], 10, 11, 13, 16, 18, 19, and 23 are operationally restricted due to wire rope, structural and concrete erosion concerns.

9.8. Bonneville Dam

9.8.1. Fall/Winter Surface Spill (Table 3). The PH1 ice & trash sluiceway (ITS) and PH2 corner collector (B2CC) are powerhouse (non-spillway) surface passage routes and will

[30] Spillbay 9 at The Dalles Dam cannot be used due to failure of the trunnion pin in 2009.

operate pursuant to criteria in FPP Chapter 2:

- March 1–8: B2CC daily 0600-1000 hours.
- March 9–25: B2CC daily 0600-1000 and 1600-2000 hours.
- March 26–August 31: B2CC 24 hours/day, 7 days/week (beginning at 0600 on March 26).
- Year-round: ITS 24 hours/day, 7 days/week. From December 15–end of February, the ITS may be closed for up to 6 hours/day for maintenance.

9.8.2. Spring Spill (Table 4): 125% gas cap up to a maximum of 150 kcfs for fish passage spill (see section 2.1), 24 hours/day, April 10–June 15.

9.8.3. Summer Spill (Table 5):

- June 16–July 31: 95 kcfs, 24 hours/day.
- August 1–31: 50 kcfs, 24 hours/day.

9.8.4. Operational Considerations:

- Maximum fish passage spill level is 150 kcfs. This constraint is based on physical model observations indicating an increased incidence of rock deposition into the spillway stilling basin at spill ≥ 150 kcfs, which has caused erosion to the structure in the past.
- Minimum spill level is 50 kcfs; however, as observed in past years, to provide acceptable juvenile fish egress conditions in the tailrace under extreme low flow conditions, lower spill levels may be considered and coordinated through the TMT and/or FPOM.
- Actual hourly average spill levels at Bonneville Dam may range up to ±3 kcfs according to spill pattern tables in FPP Chapter 2.

10. FOP IMPLEMENTATION REPORTING

The Corps posts monthly FOP Implementation Reports between April and August on the following website: https://public.crohms.org/tmt/documents/FOP_Implementation_Reports/. The updates include monthly project plots containing the following information:

- total flow: the total hourly river flow rate;
- generation flow: the hourly flow through the powerhouse turbine units;
- target spill: the spill target for that hour (Tables 3, 4 and 5);
- adjusted spill: the hourly spill level that can be achieved taking into consideration that spill may vary as a function of total river flow, forebay elevation, and generator capacity, and is

subject to routine operational adjustments that limit the ability to spill to the target spill (see section 4.1);
- actual spill: the hourly flow over the spillway; and,
- resultant 12-hour average TDG for the tailwater at each project.

The reports also provide information on non-routine or unplanned operational adjustments that arise during the spill program and address any spill adjustments due to emergency situations (such as unplanned maintenance or outages), and for contingency operations for transmission reliability. See section 4.1 for more information.

The Corps provides the following data to the public regarding project flow, spill rate, TDG level, and water temperature.

- Hourly flow, generation flow, and spill quantity data for the lower Snake and Columbia River dams are posted to the following website:
    - https://public.crohms.org/report/projdata.htm (web reports with the most recent 8 days of hourly project data and the current month of daily project data).
    - https://public.crohms.org/tmt/wq/historical/ (links to historic hourly project data files in .csv format organized by month back to 2004 including temperature and TDG information).
- Water quality data are received via satellite from TDG Fixed Monitoring Sites (FMS) in the Columbia and Snake rivers every hour and placed on a Corps public website upon receipt. Hourly TDG and water temperature data are posted to the following websites:
    - https://public.crohms.org/report/total.html (web reports with hourly TDG, project outflow and spill for the previous 3 days).
    - https://public.crohms.org/ftppub/water_quality/tdg/ (links to historic hourly water quality data files for each FMS including barometric and total gas pressure, TDG and project outflow and spill in csv-format organized by month back to 2005).
    - Using the hourly TDG readings for each station in the lower Snake and Columbia rivers, the Corps calculates both the highest 12-hour average TDG levels (Oregon and Washington spring method) and the highest consecutive 12-hour average TDG levels (Washington summer method) daily. These averages are reported at: https://public.crohms.org/ftppub/water_quality/12hr/.
- Spill cap information is posted to the following site each day: https://public.crohms.org/tmt/documents/ops/spill/caps/.

In addition to the monthly FOP Implementation Reports, the Corps provides status updates at the regularly scheduled TMT meetings about the 2025 fish passage spill operations, including reasonably detailed information that is relevant to the Corps' process for implementing fish passage spill.

EXHIBIT 114-2

IN THE UNITED STATES DISTRICT COURT

FOR THE DISTRICT OF OREGON

NATIONAL WILDLIFE FEDERATION, PACIFIC COAST FEDERATION OF FISHERMEN'S ASSOCIATIONS, INSTITUTE FOR FISHERIES RESOURCES, SIERRA CLUB, IDAHO RIVERS UNITED, NORTHWEST SPORT FISHING INDUSTRY ASSOCIATION, NW ENERGY COALITION, COLUMBIA RIVERKEEPER, and **FEDERATION OF FLY FISHERS,**

Plaintiffs,

and

STATE OF OREGON, SPOKANE TRIBE OF INDIANS, and **COEUR D'ALENE TRIBE,**

Intervenor-Plaintiffs,

v.

NATIONAL MARINE FISHERIES SERVICE, U.S. ARMY CORPS OF ENGINEERS, U.S. BUREAU OF

Case No. 3:01-cv-640-SI

AMENDED OPINION AND ORDER[1]

[1] In response to Plaintiffs' Motion for Clarification, ECF 2669, the Court issues the following Amended Opinion and Order, filed concurrently with the Amended Preliminary Injunction Order. The amendments correct scrivener's and other non-substantive errors. No changes substantively affect the Court's reasoning or holding. Federal Defendants either take no position on or do not object to the amendments. ECF 2670 at 2 n.2.

RECLAMATION, and **U.S. FISH AND WILDLIFE SERVICE**,

Defendants,

and

PUBLIC POWER COUNCIL, COLUMBIA-SNAKE RIVER IRRIGATORS ASSOCIATION, NORTHWEST RIVER PARTNERS, CONFEDERATED SALISH AND KOOTENAI TRIBES, STATE OF MONTANA, INLAND PORTS AND NAVIGATION GROUP, STATE OF IDAHO, KOOTENAI TRIBE OF IDAHO, NORTHWEST IRRIGATION UTILITIES, FRANKLIN COUNTY FARM BUREAU FEDERATION, GRANT COUNTY FARM BUREAU FEDERATION, WASHINGTON FARM BUREAU FEDERATION, and **NORTHWEST REQUIREMENTS UTILITIES**,

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Michael H. Simon, District Judge.

For decades, the battle for the life of threatened and endangered salmon and steelhead has not been fought at the end of a hook and line, nor in the woven threads of a fishing net, nor even based on the appetites of sea lions, avian predators, or killer whales. Instead, the greatest battle has been waged in the courts.[2] Although people have debated various definitions of "jeopardy" and whether mitigation actions are sufficiently "certain" to occur, the abundance of these salmonids has dwindled to near extinction levels. One of the foundational symbols of the West, a critical recreational, cultural, and economic driver for Western states, and the beating heart and guaranteed resource protected by treaties with several Native American tribes is disappearing from the landscape. And yet the litigation continues in much the same way as it has for 30 years.

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[2] The 2020 Biological Opinion ("BiOp"), at issue in this Opinion and Order, is the latest in a series of biological opinions issued by NOAA Fisheries (originally known as the "National Marine Fisheries Service" or "NMFS") since 1992 relating to operations of the Federal Columbia River Power System. NOAA Fisheries previously issued biological opinions that were challenged in this lawsuit in 2000, 2004, 2008, a supplemental biological opinion in 2010, and 2014. Each time, the Court, first acting through U.S. District Judge James A. Redden, and then through the undersigned judge, found certain conclusions by NOAA Fisheries in the biological opinions to be arbitrary and capricious. *See Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, 254 F. Supp. 2d 1196 (D. Or. 2003) ("*NMFS I*") (2000 BiOp); *Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, 2005 WL 1278878 (D. Or. May 26, 2005) ("*NMFS II*"), *aff'd by Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, 524 F.3d 917 (9th Cir. 2008) ("*NMFS III*") (2004 BiOp); *Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, 839 F. Supp. 2d 1117 (D. Or. 2011) ("*NMFS IV*") (2008/2010 BiOp); *Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, 184 F. Supp. 3d 861 (D. Or. 2016) ("*NMFS V*") (2014 BiOp).

Additionally, in 2005 and 2014 the courts hearing this case also litigated preliminary injunctions, predominately involving spill. *See Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, 2005 WL 1398223 (D. Or. June 10, 2005) ("*NMFS VI*"), *aff'd in part, remanded in part*, 418 F.3d 971 (9th Cir. 2005), *withdrawn from bound volume, opinion amended and superseded*, 422 F.3d 782 (9th Cir. 2005) ("*NMFS VII*"); *Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, 2017 WL 1829588 (D. Or. April 3, 2017) ("*NMFS VIII*"), *aff'd in part, appeal dismissed in part by Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, 886 F.3d 803, 817 (9th Cir. 2018) ("*NMFS IX*").

In 2016, the Court concluded that the 2014 Biological Opinion ("BiOp") "continue[d] down the same well-worn and legally insufficient path taken during the last 20 years" by "impermissibly rel[ying] on supposedly precise, numerical survival improvement assumptions from habitat mitigation efforts that, in fact, have uncertain benefits and are not reasonably certain to occur," "fail[ing] adequately to consider the effects of climate change," and "rel[ying] on a recovery standard that ignores the dangerously low abundance levels of many of the populations of the listed species." *NMFS V*, 184 F. Supp. 3d at 876. But in addition to invalidating the 2014 BiOp, the Court also found that the Federal Defendants[3] violated the National Environmental Policy Act ("NEPA"). The Court required the Federal Defendants to prepare a comprehensive environmental impact statement ("EIS"). This was a new requirement for the Federal Columbia River Power System ("FCRPS" or "CRS"), which the Court noted could provide an opportunity for "new and innovative solutions" that "may be able to break through any logjam that simply maintains the precarious status quo." *Id.* The Federal Defendants, over Plaintiffs' objection, requested five years, until March 2021, to complete the comprehensive EIS and next BiOp, which the Court granted.

The first Trump administration accelerated the schedule to complete the EIS and BiOp before the end of his presidency. The 2020 BiOp and the 2020 Columbia River System Operations Final Environmental Impact Statement ("FEIS") offered business-as-usual solutions. Indeed, the 2020 BiOp, taking a page from the 2004 BiOp, concluded that the operation of the FCRPS is not likely to jeopardize the continued existence of the threatened and endangered

[3] The Court refers to Defendants National Marine Fisheries Service, U.S. Army Corps of Engineers, the Bureau of Reclamation, and U.S. Fish and Wildlife Service as the "Federal Defendants." For purposes of this Opinion and Order, the Court refers collectively to the Federal Defendants and Intervenor-Defendants as "Defendants."

salmonids. Plaintiffs immediately returned to court, challenging the 2020 BiOp and the 2020 FEIS.

When President Joseph R. Biden, Jr. took office, the parties stayed the litigation. The parties worked in mediation toward a global resolution of issues relating to FCRPS operations and a lasting path forward to restoring salmonids in the Columbia River Basin. Based on the terms of the parties' agreement, and upon the motion of the parties, the Court stayed this litigation through December 13, 2028. After President Donald J. Trump took office for his second term, he invalidated the agreement between the parties. Plaintiffs then moved to lift the stay in this case.

Before the Court are Plaintiffs'[4] motions for preliminary injunction. Plaintiffs move under the Endangered Species Act ("ESA") for an injunction requiring the U.S. Army Corps of Engineers ("Corps") and the Bureau of Reclamation ("Reclamation") (together, "Action Agencies") to carry out certain operational and non-operational activities with respect to the FCRPS and management of the Columbia River Basin. For the reasons stated in Plaintiffs' respective briefs and related filings, with particular emphasis on those reasons discussed below, the Court grants in part and denies in part Plaintiffs' motions.

STANDARDS

"A plaintiff seeking a preliminary injunction must demonstrate that she is likely to succeed on the merits, irreparable harm in the absence of preliminary relief, that the balance of equities tips in her favor, and that an injunction is in the public interest." *Bates v. Pakseresht*, 146 F.4th 772, 783 (9th Cir. 2025) (citing *Winter v. Nat. Res. Def. Council, Inc.*, 555

[4] For purposes of this Opinion and Order, the Court refers collectively to the NWF Plaintiffs and Intervenor-Plaintiff Oregon as "Plaintiffs."

U.S. 7, 20 (2008)). "When the government is a party, the last two factors (equities and public interest) merge." *E. Bay Sanctuary Covenant v. Biden*, 993 F.3d 640, 668 (9th Cir. 2021).

A preliminary injunction also "may issue where 'serious questions going to the merits were raised and the balance of hardships tips sharply in plaintiff's favor' if the plaintiff 'also shows that there is a likelihood of irreparable injury and that the injunction is in the public interest.'" *Planned Parenthood Great Nw., Hawaii, Alaska, Indiana, Kentucky v. Labrador*, 122 F.4th 825, 844 (9th Cir. 2024) (quoting *All. for the Wild Rockies v. Cottrell,* 632 F.3d 1127, 1135 (9th Cir. 2011). The Ninth Circuit has a "'sliding scale' approach, in which 'the elements of the preliminary injunction test are balanced, so that a stronger showing of one element may offset a weaker showing of another.'" *Id.* (quoting *All. for the Wild Rockies*, 632 F.3d at 1131). In addition, "[d]ue to the urgency of obtaining a preliminary injunction at a point when there has been limited factual development, the rules of evidence do not apply strictly to preliminary injunction proceedings." *Herb Reed Enters., LLC v. Florida Entmt. Mgmt., Inc.*, 736 F.3d 1239, 1250 n.5 (9th Cir. 2013); *see also Johnson v. Couturier*, 572 F.3d 1067, 1083 (9th Cir. 2009).

The already high standard for granting a preliminary injunction is further heightened when the type of injunction sought is a "mandatory injunction." *Garcia v. Google, Inc.*, 786 F.3d 733, 740 (9th Cir. 2015) (noting that the burden is "doubly demanding" for a mandatory injunction). To obtain a mandatory injunction, a plaintiff must "establish that the law and facts *clearly favor* her position, not simply that she is likely to succeed." *Id.* (emphasis in original).

"If a court determines that injunctive relief is warranted, such relief must be tailored to remedy the specific harm." *NMFS VIII*, 2017 WL 1829588, at *2 (citing *Melendres v. Arpaio*, 784 F.3d 1254, 1265 (9th Cir. 2015)).

BACKGROUND

After 25 years, the facts of this case are well-established and well-known to the parties. The case stems from the declining abundance of salmon and steelhead species in the Columbia and Snake Rivers. Every year, these fish must travel up the rivers to spawn, and their offspring must return down river to the Pacific Ocean. In the course of this journey, both adult and juvenile salmonids must navigate the dams, powerhouses, and reservoirs of the FCRPS. Since the beginning of this case, this Court and the Ninth Circuit, as well as the Federal government, have all found that this difficult and sometimes lethal odyssey is a major contributor to the dwindling numbers of salmonids returning to the Columbia and Snake Rivers each year. *See, e.g.*, *NMFS IV*, 839 F. Supp. 2d at 1131 ("As I have previously found, there is ample evidence in the record that indicates that the operation of the FCRPS causes substantial harm to listed salmonids. . . . NOAA Fisheries[5] acknowledges that the existence and operation of the dams accounts for most of the mortality of juveniles migrating through the FCRPS."); *NMFS IX*, 886 F.3d at 819-20 (concluding that irreparable harm to the listed species from the FCRPS as a whole was sufficient to support the spill injunction). There are now 13 populations of salmon and steelhead, and one smelt population, listed under the ESA and affected by the FCRPS.

In 2000, 2008, 2010, and 2014, in providing Section 7 consultations for the Action Agencies, National Marine Fisheries Service ("NMFS") found that FCRPS operations jeopardized the listed species, but with reasonable and prudent alternatives, jeopardy could be avoided. In 2004, using a novel approach to defining jeopardy, NMFS found that the FCRPS did

[5] NOAA Fisheries is the operational name of Defendant National Marine Fisheries Service and is referenced in case law referring to that agency.

not jeopardize the listed species. That BiOp was swiftly found unlawful by this Court and the Ninth Circuit.

When Plaintiffs challenged the 2014 BiOp, they also raised a challenge under NEPA. The Court found in Plaintiff's favor and required the Federal Defendants to prepare a comprehensive EIS, as well as a new BiOp.

In 2020, NMFS performed another Section 7 consultation and completed the BiOp. The scope of the 2020 BiOp is described as:

> NMFS considers the effects of the Action Agencies' proposed action (the continued operation and maintenance of the CRS dams; tributary and estuary habitat mitigation programs; conservation and safety net hatchery programs; predator management programs; and research, monitoring, and evaluation [RME] programs) on eight species of salmon (ESUs), five species of steelhead (DPSs), and the Southern DPS of Pacific Eulachon and their designated critical habitat.

2020 BiOp at 45.[6] This BiOp, similar to the 2004 BiOp, used a novel approach to evaluating jeopardy and concluded that the FCRPS operations did not jeopardize the continued existence of the listed species or result in the destruction or adverse modification of their habitat. The Federal Defendants also completed the EIS as directed by the Court.

Following the completion of the 2020 BiOp, the Corps and Reclamation, together with non-party Bonneville Power Administration ("BPA") issued a Joint Record of Decision ("ROD") on the operation of the FCRPS. For purposes of ESA compliance, the ROD relied on the conclusion by NMFS in its 2020 BiOp that the Proposed Action reflected in the ROD did not

[6] The continued operation and maintenance of the CRS dams; tributary and estuary habitat mitigation programs; conservation and safety net hatchery programs; predator management programs; and RME programs are referred to in this Opinion and Order as the "Proposed Action."

jeopardize the continued existence of listed salmon and steelhead. Plaintiffs filed an Eighth Supplemental Complaint in this case, challenging both the 2020 BiOp and the 2020 FEIS.

In 2021, after President Biden took office, the parties requested that the Court stay this case so they could engage in mediation. In 2023, the parties entered into a Memorandum of Understanding ("MOU") that showed great promise for resolving the myriad challenges facing the ecological and economic future of the Columbia River Basin. As a result of that MOU, the Court stayed this litigation through December 2028. In June 2025, this budding consensus collapsed as the Federal Defendants withdrew from the MOU. Thus, the Court lifted the stay.

Plaintiffs filed the pending Motions for Preliminary Injunction, requesting relief beginning on March 1, 2026, and remaining in place until further order of the Court. *See* ECF 2530-2. In order to reduce alleged irreparable harm to the listed salmonids, Plaintiffs ask that the Court require Federal Defendants to do the following:

> (1) increase spill to the maximum level that meets but does not exceed state water quality standards at the federal dams on the four lower Columbia and four lower Snake Rivers for the spring spill season;
>
> (2) restore summer spill at all eight of these projects to the levels set in prior Biological Opinions ("BiOps") for the entire summer spill season;
>
> (3) provide continuous 24-hour spill from during the fall and winter spill seasons at all eight projects through the operation of at least one spillway weir or other surface passage route;
>
> (4) operate the reservoirs above the four lower Snake River dams at their minimum operating pool ("MOP") elevations with a one-foot operating range from March 1 through August 31;
>
> (5) operate the reservoirs above three of the four mid-Columbia dams (Bonneville, the Dalles, and McNary) at their MOP elevations with a 1.5-foot operating range from March 1 through August 31;

> (6) operate the reservoir above the John Day dam at its minimum irrigation pool ("MIP") elevation with a 1.5 foot operating range from March 1 through June 15 and MIP plus one foot with a 1.5 foot operating range from June 16 through August 31, beginning in 2026, and develop and submit to the Court within one year of entry of an order for an implementation plan to operate the John Day reservoir at its MOP elevation with a 1.5-foot operating range from March 1 through August 31; and,
>
> (7) implement emergency conservation measures for several deeply imperiled populations.

ECF 2526 at 9-10.

DISCUSSION

A. The Court has the Jurisdiction and Authority to Enter an Injunction

The Federal Defendants argue that the Court lacks jurisdiction to rule on Plaintiffs' motions, for the reasons argued in the Federal Defendants' separate motion to dismiss. ECF 2567. As the Court will explain in a separate and forthcoming Opinion and Order resolving that motion to dismiss, the Court rejects the arguments made by the Federal Defendants and concludes that this Court has subject matter jurisdiction over this case.

Additionally, the Federal Defendants argue that "Plaintiffs' Injunction oversteps traditional bounds of equity in multiple and unjustified ways" because the relief requested is "systemic." ECF 2569 at 30-31. The Federal Defendants further assert that the Supreme Court's recent ruling in *Trump v. CASA Inc.*, newly limits the Court's equitable powers to grant injunctive relief to that which "encompasses only those sorts of equitable remedies traditionally accorded by courts of equity at our country's inception." 606 U.S. 831, 841 (2025) (cleaned up); ECF 2569 at 30.

The Court disagrees with the Federal Defendants' characterization of *CASA*. The Supreme Court in *CASA* did not fundamentally alter the boundaries of a district court's equitable powers. Rather, in considering a district court's ability to issue universal injunctions, the

Supreme Court clarified that a district court, acting in equity, may award up to complete relief between the parties, but no more. 606 U.S. at 851-54. The Court does not today enter a universal or nationwide injunction, nor has it been asked to do so.

Further, the Court is not granting the full relief requested by Plaintiffs. The Court declines to impose many of Plaintiffs' requests challenged by the Federal Defendants as outside of this Court's equitable authority to grant. But it is undisputed that this Court previously has entered injunctions that "modif[y] CRS operations," as Defendants acknowledge. ECF 2569 at 30; *see also NMFS VII*, 422 F.3d at 797-99 (affirming Judge Redden's preliminary injunction requiring spill); *NMFS IX*, 886 F.3d at 817-824 (affirming the undersigned judge's preliminary injunction requiring spill and PIT tag monitoring). The injunction granted by the Court here is not fundamentally different than those that have come before. The Court grants relief only to the parties. To the extent that Plaintiff's Injunction requires tailoring, the Court does that below.

B. The *Winter* Factors

1. Plaintiffs are Likely to Succeed on the Merits[7]

a. Legal Standards for Plaintiff's Claims

Congress passed the ESA to "provide a means whereby the ecosystems upon which endangered species and threatened species depend may be conserved, [and] to provide a program for the conservation of such endangered species and threatened species[.]" 16 U.S.C. § 1531(b). The ESA contains a broad and ambitious definition for the term "conservation," including "the use of all methods and procedures which are necessary to bring any endangered species or threatened species to the point at which the measures provided pursuant to this chapter are no

[7] The Court makes this determination on a truncated preliminary injunction record, with a shortened briefing and evidentiary record. The Court makes this determination without prejudice to fully consider all arguments and evidence when evaluating Plaintiffs' claim on the merits.

longer necessary." *Id.* § 1532(3). The law imposes many requirements on federal agencies, including a requirement that agencies ensure that any action they authorize, fund, or carry out "is not likely to jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of such species' habitat." *Id.* § 1536(a)(2).

In order to achieve this requirement, any federal agency intending to carry out an action that may affect a listed species or their critical habitat must first consult with either NMFS or the Fish and Wildlife Service ("FWS"), depending on the species. *Id.* §§ 1536(a)-(c); 50 C.F.R. § 402.01. In this case, the relevant service is NMFS. After the consultation is initiated, NMFS must prepare a biological opinion that determines whether the proposed action is likely to "jeopardize the continued existence" of a listed species or result in the destruction or adverse modification of a critical habitat. 16 U.S.C. § 1531(b)-(c).

An action jeopardizes the continued existence of a listed species if it "reasonably would be expected, directly or indirectly, to reduce appreciably the likelihood of both the survival and recovery of a listed species in the wild by reducing the reproduction, numbers, or distribution of that species." 50 C.F.R. § 402.02. In making a jeopardy determination, NMFS must employ "the best scientific and commercial data available." 16 U.S.C. § 1536(a)(2). If jeopardy is likely, NMFS must also provide "reasonable and prudent" alternatives to the action that would avoid jeopardy. *Id.* §§ 1536(b)-(c). As explained by the Federal Defendants, "[t]o prepare its BiOp, NMFS evaluates the current status of a species and critical habitat, the environmental baseline, and the effects of the action and cumulative effects on the listed species and critical habitat in the action area." ECF 2569 at 19 (citing 50 C.F.R. § 402.14(g)(2)-(3)).

ESA claims are reviewed under the well-established standards of the Administrative Procedure Act ("APA"). Under those standards, an agency action must be upheld unless it is

"arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with the law[.]" 5 U.S.C. § 706(2)(A). "[T]he touchstone of 'arbitrary and capricious' review under the APA is 'reasoned decisionmaking.'" *Altera Corp. & Subsidiaries v. Comm'r of Internal Revenue*, 926 F.3d 1061, 1080 (9th Cir. 2019) (quoting *Motor Vehicle Mfrs. Ass'n of the U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 52 (1983)). "[A]n agency's action can only survive arbitrary or capricious review where it has articulated a satisfactory explanation for its action including a rational connection between the facts found and the choice made." *All. for the Wild Rockies v. Petrick*, 68 F.4th 475, 493 (9th Cir. 2023) (cleaned up); *see also Gill v. U.S. Dep't of Just.*, 913 F.3d 1179, 1187 (9th Cir. 2019) ("An agency must 'examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made.'" (quoting *State Farm*, 463 U.S. at 43)). *Post-hoc* rationalizations cannot justify an agency's actions. *See Citizens to Preserve Overton Park, Inc. v. Volpe*, 401 U.S. 402, 419 (1971), *abrogated on other grounds by Califano v. Sanders*, 430 U.S. 99, 105 (1977).

The Supreme Court has often observed that the reasoned decisionmaking requirement includes a duty to explain any "departure from prior norms." *Atchison, T. & S. Ry. Co. v. Wichita Bd. of Trade*, 412 U.S. 800, 808 (1973); *see also Int'l Union, UAW v. NLRB*, 802 F.2d 969, 973-74 (7th Cir. 1986) ("[A]n administrative agency is not allowed to change direction without some explanation of what it is doing and why."). "Unexplained inconsistency" between agency actions is "a reason for holding an interpretation to be an arbitrary and capricious change." *Nat'l Cable & Telecomms. Ass'n v. Brand X Internet Servs.*, 545 U.S. 967, 981 (2005).

b. Discussion

Here, Plaintiffs are likely to succeed on their underlying challenge to the 2020 BiOp, and thus are likely to succeed on their challenge to the 2020 ROD that relies heavily on that 2020

BiOp. Plaintiffs are likely to succeed on their arguments that the BiOp, and thus the ROD, fails for at least four reasons. First, the BiOp's jeopardy analysis improperly considered the environmental baseline, resulting in a flawed analytic approach that is both impermissibly comparative and unacceptably limited in its evaluation of the Proposed Action's anticipated impacts. Second, the BiOp's jeopardy analysis impermissibly relies on uncertain benefits. Third, the BiOp does not properly account for climate change in its jeopardy analysis. Finally, the BiOp fails properly to engage in a recovery analysis as required by the ESA.

i. Preliminary Arguments

The Federal Defendants argue that a flawed BiOp does not doom the ROD because the Action Agencies conducted independent analyses of the action's impact on listed species, citing ACE000068214-23. The cited pages, however, reflect *BPA's* statement of its final agency finding.[8] The Corps' final agency finding is set forth in Section 6.1 and consists of a single paragraph, which summarizes the Corps' NEPA analysis and adoption of the Preferred Alternative in the FEIS and then states: "Further, the Corps has determined, and the NMFS and USFWS Biological Opinions demonstrate, based on the best available commercial and scientific information that the Corps' implementation of the Selected Alternative will not jeopardize listed species or adversely modify or destroy critical habitat." ACE000068212; *see also* ACE000068160 (Corps' Decision Summary, summarizing its adoption of the FEIS and stating "Consultation on the Selected Alternative has been completed per Section 7(a)(2) of the Endangered Species Act (ESA) and incorporated into the Selected Alternative. The Corps has determined, and the National Marine Fisheries Service (NMFS) and U.S. Fish and Wildlife

[8] In addition to the cited pages being BPA's agency finding, they also contain significant discussion and quotations from the 2020 BiOp, and do not represent an "independent" analysis.

Service (USFWS) CRS Biological Opinions demonstrate, based on the best available commercial and scientific information, that the Corps' implementation of the Selected Alternative will not jeopardize listed species or adversely modify or destroy critical habitat.").

Reclamation's final agency finding, in Article 6.2, is even shorter and provides no specific Section 7 statement, focusing instead solely on NEPA and Reclamation's adoption of the Preferred Alternative. ACE000068213. Reclamation, however, includes at the beginning of the ROD, in its Decision Summary, that "[t]he NMFS and and USFWS CRS Biological Opinions demonstrate, based on the best available commercial and scientific information, that Reclamation's implementation of the Selected Alternative will not jeopardize listed species or adversely modify or destroy critical habitat." ACE000068161.

Whether looking at the Action Agencies' Decision Summary or Final Agency Findings, the statements do not contain any independent analysis. And even considering the entire ROD as a statement of agency findings, they are not independent of the 2020 BiOp.

The ROD expressly incorporates the 2020 BiOp. ACE000068160. The ROD largely cites the 2020 FEIS, because it primarily is a NEPA document that also serves as a Section 7 consultation ROD. There is substantial overlap between the 2020 FEIS and 2020 BiOp in the relevant sections. Additionally, with respect to the ROD's sections relating to the ESA, the statements are brief, conclusory, and either expressly rely on the 2020 BiOp or do not represent independent analysis from the 2020 BiOp. Thus, the Court rejects the Federal Defendants' argument that the Action Agencies' findings in the ROD represent independent analyses that immunize the Action Agencies if Plaintiffs are found likely to succeed on their claim that NMFS violated the APA in issuing the 2020 BiOp.

The Federal Defendants also argue that Plaintiffs cannot possibly succeed on the merits because the Court has not *yet* invalidated the 2020 BiOp, and thus there is no basis to argue that the Corps or Reclamation was arbitrary or capricious in relying on NMFS's 2020 BiOp when adopting it in the 2020 ROD. The Federal Defendant's reasoning here is unclear. A court will never have invalidated a BiOp at the time it is adopted by an action agency. A preliminary injunction in the context of ESA consultation generally will require a court to evaluate whether the plaintiff is likely to succeed on the merits of its challenge to the underlying BiOp, and thus to the action agency's conduct in adopting that BiOp.

Further, the Federal Defendants' argument is particularly specious in *this* case, where the Action Agencies have the benefit of nearly 30 years of litigation over the FCRPS, and 25 years of litigating this specific case. In the direct history of this case, this Court, including with affirmance by the Ninth Circuit, repeatedly has rejected BiOps by NMFS with similar deficiencies as Plaintiffs allege in the pending complaint. *See, e.g.*, *NMFS III*, 524 F.3d at 928-33 (affirming district court rejection of 2004 BiOp for deficiencies including an improperly comparative jeopardy analysis that considered the FRCPS in a "vacuum," failed to consider the severely degraded baseline condition, and attempted a "sleight of hand" to "manipulat[e] the variables" to avoid acknowledging that the operations of the dams are discretionary and must be included in the jeopardy analysis, and failing to properly to analyze recovery); *NMFS V*, 184 F. Supp. 3d at 897-901 (discussing failing to analyze recovery in 2014 BiOp); *id.* at 901-14 (actions with uncertain benefits); *id.* at 914-23 (climate change). Even if some notice were required to Action Agencies of the potential arbitrary and capricious nature of the specific consultation, which the Court does not agree is required, the Action Agencies were on notice of the potential

arbitrary and capricious nature of adopting NMFS's BiOps, which were found to violate the ESA the last *four times* they were challenged *in this case*.

ii. Jeopardy Analysis—Environmental Baseline

Plaintiffs are likely to succeed in their contention that in the 2020 BiOp, NMFS's approach to the required jeopardy analysis was improperly evaluated the environmental baseline, resulting in an impermissible comparative analysis, similar to the one from the 2004 BiOp that was rejected by this Court and the Ninth Circuit. The Federal Defendants argue that this analysis is proper under the revised regulations promulgated in 2019. The Court rejects this argument.

In 2019, NMFS and USFWS revised some of the regulations under the ESA, including the definition of the term "environmental baseline." Endangered and Threatened Wildlife and Plants; Regulations for Interagency Cooperation, 84 Fed. Reg. 44976, 45016 (Aug. 27, 2019) ("2019 Am.").[9] The definition established at the time was:

> Environmental baseline refers to the condition of the listed species or its designated critical habitat in the action area, without the consequences to the listed species or designated critical habitat caused by the proposed action. The environmental baseline includes the past and present impacts of all Federal, State, or private actions and other human activities in the action area, the anticipated impacts of all proposed Federal projects in the action area that have already undergone formal or early section 7 consultation, and the impact of State or private actions which are contemporaneous with the consultation in process. The consequences to listed species or designated critical habitat from ongoing agency activities or existing agency facilities that are not within the agency's discretion to modify are part of the environmental baseline.

Id. A consultation, however, must still analyze "the effects of all of the discretionary

[9] This term was redefined under the Biden administration in 2024, *see* 89 Fed. Reg. 24268, and the second Trump administration has proposed new rules in November 2025 setting a definition of environmental baseline similar to its 2019 definition, *see* 90 Fed. Reg. 52600.

operations" of a proposed action, "even those operations that the Federal agency proposes to keep the same." *Id.* at 44978.

Plaintiffs argue that the Federal Defendants include general operations of the FCRPS in the environmental baseline and have considered only the effect of the *changes* in their operational plan rather than the effects of the entire Proposed Action. By way of example, if normal operation of Bonneville Dam kills 1000 fish, and the proposed 2020 operation includes modifications that would result in only killing 900 fish, then the Federal Defendants' analysis is that the proposed action saves 100 fish, thereby benefitting the species and not causing jeopardy, instead of that the action kills 900 fish. If the entire fish population is 1100, then killing 900 might jeopardize the species, regardless of whether dam operations improved the final number of fish by 100.

The Federal Defendants object generally to the proposition that they improperly assessed the environmental baseline or the effects of FCRPS operations. They argue that Plaintiffs must identify specific discretionary hydropower operations that were inappropriately included in the baseline, as opposed to NMFS having to identify the nondiscretionary elements it included in the assessment. The Federal Defendants also argue the 2020 BiOp is dissimilar to the 2004 BiOp because that analysis used a "reference" hydropower operation in its baseline and the 2020 BiOp does not.

The jeopardy analysis in the 2020 BiOp is a "novel" approach that is "completely at odds with NMFS's prior scientific approaches, [thus] it merits little deference." *See NMFS III*, 524 F.3d at 928. Plaintiffs are likely to succeed in their argument that the 2020 BiOp suffers from the same fatal defects as the 2004 BiOp. The 2004 BiOp used the "reference" dam operation in its environment baseline "to avoid 'trying to precisely determine the extent of the Action Agencies'

discretionary operation.'" *Id.* The 2020 BiOp does not use a "reference" operation to avoid trying to precisely determine the extent of discretionary versus nondiscretionary operations—it just ignores making that determination. Instead, NMFS repeatedly offers a boilerplate statement that "[t]he consequences to listed species . . . from ongoing agency activities or existing agency facilities that are not within the agency's discretion to modify are part of the environmental baseline (50 CFR 402.02)." *See* 2020 BiOp at 125, 320, 452, 556, 663-64, 778, 890, 984, 1048, 1116-17, 1185, 1245-46, 1297, 1342. But simply issuing that statement without identifying what activities are and are not within the agency's discretion provides no assurance that NMFS actually distinguished between the two and does not provide a discernable path for the Court to review whether NMFS made accurate determinations. What NMFS did was focus on the effects of the *changes* in the proposed operations, thereby silently including existing operations as part of the baseline. *See* ECF 2526 at 24-26 (identifying examples in the 2020 BiOp). The bottom line is that "NMFS may not avoid determining the limits of the action agencies' discretion . . . thereby excluding them from the requisite ESA jeopardy analysis," *NMFS III*, 524 F.3d at 929, whether by "using a reference operation to sweep" operations into the baseline, *id.*, or silently sweeping operations into the baseline. *See id.* at 928 (explaining that an agency may not "ignore potential jeopardy risks by labeling parts of an action nondiscretionary").

The 2020 BiOp's inclusion of dam operations in the baseline is improper under *NMFS III*. The 2019 definition of environmental baseline that distinguishes between discretionary and nondiscretionary conduct does nothing to change the key holding of *NMFS III*. That regulation is not a change from the Ninth Circuit's decision. The Ninth Circuit amended its decision after the Supreme Court issued *National Ass'n of Home Builders v. Defenders of Wildlife*, 551 U.S. 644 (2007), which granted *Chevron* deference to the ESA regulation stating

that consultation applies to discretionary federal involvement or control.[10] *See NMFS III*, 524 F.3d at 927. The Ninth Circuit then considered whether FCRPS dam operations were discretionary, and unequivocally concluded that they were. *See id.* at 928-29. The court stated that the *existence* of the dams was part of the environmental baseline, but the *operation* of the dams was discretionary. *Id.* at 930-31.

Nor may the Federal Defendants simply compare the proposed operation to a baseline that includes FCRPS operations. A similar comparison approach was rejected by the Ninth Circuit in reviewing the 2004 BiOp:

> NMFS argues that, under this definition, it may satisfy the ESA by comparing the effects of proposed FCRPS operations on listed species to the risk posed by baseline conditions. Only if those effects are "appreciably" worse than baseline conditions must a full jeopardy analysis be made. Under this approach, a listed species could be gradually destroyed, so long as each step on the path to destruction is sufficiently modest. This type of slow slide into oblivion is one of the very ills the ESA seeks to prevent.

NMFS III, 524 F.3d at 930. This conclusion was not altered by the amended environmental baseline definition.

Plaintiffs are likely to succeed in their argument that at its core, the 2020 BiOp's jeopardy analysis reverted back to the 2004 BiOp's attempt to "manipulat[e] the variables to achieve a 'no jeopardy' finding." *Id.* at 933.

iii. Jeopardy Analysis—Uncertain Benefits

Plaintiffs also challenge the 2020 BiOp as improperly basing its "no jeopardy" finding in part by relying on benefits from uncertain and ill-defined future mitigation actions. Courts in this case repeatedly have found lacking NMFS's reliance on future benefits that were not sufficiently

[10] These opinions were issued before *Loper Bright Enters. v. Raimondo*, 603 U.S. 369 (2024).

certain to occur. *See, e.g.*, *NMFS III*, 524 F.3d at 935-36; *NMFS IV*, 839 F. Supp. 2d at 1125; *NMFS V*, 184 F. Supp. 3d at 914.

In 2019, the EPA also amended its regulations regarding its interpretation of what the ESA required in terms of mitigating actions. The EPA explained:

> The regulatory change to § 402.14(g)(8) is to make it clear that, just like aspects of the proposed action with adverse effects, the Services are not required to obtain binding plans or other such documentation prior to being able to lawfully evaluate the effects of an action as proposed, including any measures included in the proposed action that would avoid, minimize, or offset adverse effects. However, the Services are also moving forward with revisions to § 402.14(c)(1). Those revisions require a Federal agency seeking to initiate formal consultation to provide a description of the proposed action, including any measures intended to avoid, minimize, or offset effects of the proposed action. If the description of proposed measures fails to include the level of detail necessary for the Services to understand the action and evaluate its effects to listed species or critical habitat, then the Services will be unable to take into account those effects when developing our biological opinion. To avoid confusion and reinforce that an appropriate level of specificity regarding the description of measures included in the proposed action may be necessary to provide sufficient detail to assess the effects of the action on listed species and critical habitat, the Services eliminated the reference to "specific" plans in our final revisions to § 402.14(g)(8). The Services do not intend to hold these actions to either a higher or lower standard than any other type of action or measure proposed by a Federal agency. Any type of action proposed by a Federal agency receives a presumption that it will occur, but it must also be described in sufficient detail that the Services can both understand the action and evaluate its adverse effects and beneficial effects.

2019 Am., 84 Fed. Reg. at 45003.[11]

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[11] The revised § 402.14(g)(8) provided: "In formulating its biological opinion, any reasonable and prudent alternatives, and any reasonable and prudent measures, the Service will use the best scientific and commercial data available and will give appropriate consideration to any beneficial actions as proposed or taken by the Federal agency or applicant, including any actions taken prior to the initiation of consultation. Measures included in the proposed action or a reasonable and prudent alternative that are intended to avoid, minimize, or offset the effects of an action are considered like other portions of the action and do not require any additional

The analysis in the 2020 BiOp for estuary and tributary habitat improvement projects likely fails even under the 2019 revised regulations. For estuary habitat improvement projects, the 2020 BiOp describes the intent to "prioritize habitat improvement sites by identifying regions with the greatest potential to benefit yearling and subyearling life-history types of ESA-listed salmon and steelhead" and provides a list of example projects. 2020 BiOp at 74. It then establishes a "5-year rolling review" to "evaluate the acreage restored to date and projects available for the next 5-year period." *Id.*

Under the 2019 amended regulations, the burden was on the Action Agencies to provide NMFS with sufficient detail of proposed mitigating actions (such as estuary and tributary habitat improvement), including location; specific components of the mitigating action and how it will

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demonstration of binding plans."

The revised § 402.14(c)(1) provided:

> A written request to initiate formal consultation shall be submitted to the Director and shall include:
>
> (i) A description of the proposed action, including any measures intended to avoid, minimize, or offset effects of the action. Consistent with the nature and scope of the proposed action, the description shall provide sufficient detail to assess the effects of the action on listed species and critical habitat, including:
>
> (A) The purpose of the action;
>
> (B) The duration and timing of the action;
>
> (C) The location of the action;
>
> (D) The specific components of the action and how they will be carried out;
>
> (E) Maps, drawings, blueprints, or similar schematics of the action; and
>
> (F) Any other available information related to the nature and scope of the proposed action relevant to its effects on listed species or designated critical habitat.

be carried out; maps, drawings, or similar schematics; and other similar documents describing the scope of the proposal. The revised regulations ensured that there need not be "binding plans," but the projects were still required to be described with specificity. This is so that NMFS could then "assess the effects of the action on listed species and critical habitat." 50 C.F.R. § 402.14 (g)(8), (c)(1)(i).

The 2020 BiOp provides an insufficient analysis with respect to estuary habitat. There is no description of specific projects nor any assessment of the benefits to the species or habitat of any detailed project. Plaintiffs are likely to succeed on their claim that NMFS's reliance on certain benefits from estuary habitat projects that were not reasonably certain to occur was arbitrary and capricious.

For tributary habitat improvement, the 2020 BiOp incorporated by reference the Biological Assessment ("BA") submitted by the Action Agencies. The Federal Defendants cite the pages of the BA that provided "proposed habitat metrics" that the Action Agencies hope to achieve through tributary habitat restoration. ACE00105608-14. These metrics included the amount of flow protected (by cfs); flow enhanced (by acre-feet); number of entrainment screenings; habitat access (in miles); stream complexity (in miles); and riparian habitat improvement (in miles). ACE001059609. These are end goals. They are not *projects* that reach those goals. In other words, it is great to state that the Action Agencies intend to improve 156 acres of riparian habitat in the Lower Snake River and enhance 9,680 acre-feet of flow on the Upper Salmon, but how do they intend to achieve that goal? The 2019 revised regulations included a requirement that the Action Agencies detail the "specific components of the action and how they will be carried out," not simply the end result. 50 C.F.R. § 402.14(c)(1)(i)(D)

The BA contained a similar plan for monitoring, evaluating, and reporting tributary habitat projects as estuary projects—"a series of prospective 5-year implementation plans" with annual reporting. *See* ACE001059611. Again, this discussion did not include any project or how that project would be carried out. Plaintiffs are likely to succeed in their argument that NMFS simply accepting that these end achievements will be realized and calculating the benefit to the species of all of these being accomplished is contrary to the ESA. As the Court previously explained, "NOAA Fisheries places all of the risk of that uncertainty on the species. This is precisely what the ESA does not permit." *NMFS V*, 184 F. Supp. 3d at 906; *see also Tenn. Valley Auth. v. Hill* ("*TVA*"), 437 U.S. 153, 194 (1978) ("Congress has spoken in the plainest of words, making it abundantly clear that the balance has been struck in favor of affording endangered species the highest of priorities, thereby adopting a policy which it described as 'institutionalized caution.'"); *Sierra Club v. Marsh*, 816 F.2d 1376, 1386 (9th Cir.1987) (noting that the "benefit of the doubt" must be given to the endangered species and that the risk of failure of mitigation must fall on the project), *abrogation on other grounds recognized by Cottonwood Envtl. Law Ctr. v. U.S. Forest Serv.*, 789 F.3d 1075, 1088 (9th Cir. 2015). Additionally, given the history in this case of habitat restoration projects falling significantly behind in expected completion, NMFS had even more reason to be cautious in relying on the Action Agencies' assurances that all projects will be completed and all benefits will be achieved within the BiOp time frame.

iv. Jeopardy Analysis—Climate Change

Plaintiffs contend that NMFS essentially gave lip service to climate change, noting that it exists and agreeing that it will cause significant increase in mortality to the life cycle of salmonids, without taking that increased mortality into consideration. The Federal Defendants respond that NMFS only need consider harms caused by the Proposed Action, and harm by climate change is not harm caused by the Proposed Action.

The Federal Defendants are missing the crux of Plaintiffs' argument. Plaintiffs contend that the *Proposed Action* is causing the harm. Plaintiffs point to the Federal Defendants' own modeling showing that the harm caused by the Proposed Action is significantly greater when climate change is considered. It is not the separate mortality from, for example, salmonid death in warming oceans that is being added, but the increased mortality and potential jeopardy to the species caused by the FCRPS as climate change effects are considered.[12] Yet the 2020 BiOp discounts that increased mortality as not caused by the Proposed Action. NMFS, however, is required to evaluate "what jeopardy might result from the agency's proposed actions *in the present and future human and natural contexts*." *NMFS III*, 524 F.3d at 930 ((emphasis added in *NMFS III*), quoting *Pac. Coast Fed'n of Fishermen's Ass'ns v. U.S. Bureau of Reclamation*, 426 F.3d 1082, 1093 (9th Cir. 2005)). In other words, if FCRPS operations kills more salmonids because they are weakened by the effects of climate change, or if the amount of salmonids killed by FCRPS operations is more of a threat to the sustainability of the species because they are dying in greater numbers due to climate change, that is the reality in which NMFS must assess the effects of the Proposed Action. Plaintiffs are likely to succeed in their argument that NMFS failed properly to assess the effects of the Proposed Action with climate change. *See Willamette Riverkeeper v. Nat'l Marine Fisheries Serv.*, 763 F. Supp. 3d 1203, 1237-38 (D. Or. 2025) (agreeing with the plaintiffs that NMFS failed properly to account for climate change and "evaluate the consequences" of the proposed action along with "projected worsening

[12] *See, e.g.*, NMFS00291878 (discussing that freshwater environments demonstrate "highest vulnerabilities to climate change" as well as marine environments); NMFS00291865 (same); ACE000821951 (including in a study of climate vulnerability for Pacific salmon and steelhead a chart of "highly vulnerable life stages" to climate change by species population, with several of the listed species in this case included as highly vulnerable in the "juvenile freshwater stage" and "adult freshwater stage").

conditions"; NMFS needed to assess the project "on top of climate change effects"); *see also NMFS V*, 184 F. Supp. 3d at 917 ("The Court finds that NOAA Fisheries' analysis and conclusion that the effects of climate change have been adequately assessed in the 2014 BiOp is not 'complete, reasoned, [or] adequately explained.'" (quoting *Nw. Coal. for Alts. to Pesticides (NCAP) v. EPA*, 544 F.3d 1043, 1052 n. 7 (9th Cir. 2008)). "NOAA Fisheries' analysis does not apply the best available science, overlooks important aspects of the problem, and fails properly to analyze the effects of climate change, including: its additive harm, how it may reduce the effectiveness of the [RPA] actions, particularly habitat actions that are not expected to achieve full benefits for 'decades,' and how it increases the chances of [a catastrophic] event." *Id.* at 874.

v. Recovery Analysis

A valid BiOp must "analyze effects on recovery as well as effects on survival." *NMFS III*, 524 F.3d at 932. An "agency may not resolve this difficulty by ignoring recovery needs and focusing entirely on survival." *Id.* at 932 n.11. "NMFS must conduct a full analysis of those risks and their impacts on the listed species' continued existence." *Id.* at 933. It is particularly important in this case, as the Ninth Circuit emphasized when NMFS made a "no jeopardy" finding in 2004—"the highly precarious status of the listed fishes at issue raises a substantial possibility that considering recovery impacts could change the jeopardy analysis." *Id.*

The Federal Defendants argue that recovery adequately was assessed by NMFS. NMFS first measured current key viable salmonid parameters ("VSP") of abundance, productivity, spatial structure, and diversity. It then performed COMPASS and life-cycle modeling to quantitatively estimate population abundance and productivity under the Proposed Action. NMFS finally considered that data along with other information to evaluate the Proposed Action as a whole and whether it reduced appreciably the likelihood of survival and recovery.

NMFS's final analysis primarily focused on survival. Although survival and recovery are "intertwined needs," they both must be considered. *Id.* at 932. Recovery may be out of reach even while a species clings to survival. *Id.* (rejecting NMFS's contention that it need only consider survival "[b]ecause a species can often cling to survival even when recovery is far out of reach"). NMFS's statements regarding recovery are conclusory, and based on positive VSP survival metrics. *See, e.g.*, ACE001056508 (discussing Salmon River spring/summer Chinook and concluding that "in many ways the proposed action is expected to improve the functioning of VSP parameters and thus positively contribute to the survival and recovery of the species"); ACE1056646 (same, for Snake River Basin Steelhead); ACE001056858 (same, for Snake River fall Chinook Salmon); ACE1056973 (same, for Upper Columbia River spring Chinook Salmon).

The Court previously rejected that recovery can be based on positive VSPs, without regard to overall abundance. *See NMFS V*, 184 F. Supp. 3d at 888 (rejecting NMFS's standard because the VSP "metrics considered by NOAA Fisheries [did] not take into account whether populations remaining at significantly low abundance numbers, even though the populations may be growing incrementally, appreciably diminish the likelihood of recovery"); *see also id.* ("The three [VSP] metrics indicate a trend in growth from wherever an existing population may be, but provide no rational connection from that existing population or the incrementally larger population anticipated after the RPA actions to ensuring no decreased risk of reaching recovery. A population that is dangerously low in abundance could be increasing, but by only a very few fish per year for the BiOp period, resulting in an abundance level at the end of the BiOp period that remains dangerously low despite the increase in population."). This type of analysis is "untethered to actual population levels and is not tied to any rough understanding of what

constitutes recovery so that NOAA Fisheries can reasonably determine that the RPA actions do not appreciably diminish the chances of reaching recovery." *Id.* at 898.

NMFS's focus on the positive VSP metrics is a focus on an increase in population. "An increasing population, however, does not necessarily equate to a 'no jeopardy' finding." *Id.* at 888. Plaintiffs are likely to succeed on their assertion that NMFS did not properly evaluate recovery.

2. Irreparable Harm

Plaintiffs are likely to suffer irreparable harm in the absence of preliminary relief. The Proposed Action is largely a continuation of previous FCRPS operations found to be in violation of the ESA. *See* Bowles Decl. ¶¶ 50-56, ECF 2531. Given the current record, it is reasonable to conclude that the listed species' prognosis is as bad as—or worse than—it has ever been. As discussed at length by Plaintiffs and their aligned *amici* many of the populations have reached the quasi-extinction threshold (meaning that the population has 50 or fewer natural-origin spawners for four consecutive years, Hesse Decl. ¶ 29, ECF 2541). Others are on trend to reach this threshold within a few years. This places the species at an alarming risk for extirpation. For the reasons discussed by Plaintiffs and their aligned *amici*, the Court rejects Defendants' arguments that a few intermittent strong returns means the species are improving or on the road to recovery. *See, e.g.*, ECF 2623 at 25-27; 2630 at 3-5; *see, also, e.g.*, ACE001056502 (evaluating Snake River spring/rummer Chinook salmon and noting that "[t]he most recent status review (NMFS 2016b) indicated that most populations (19 of 22 populations for which estimates were available) increased in abundance, compared to the previous review, but that all but one population remained at high overall risk" and that "[m]ore recent adult returns (2014 to 2019) have been substantially below average for most, but not all, populations/MPGs"); NMFS, *Rebuilding Interior Columbia Basin Salmon and Steelhead*, at 22 (Sept. 30, 2022) (ECF 2529-7)

("*Rebuilding Report*") (stating that "in the near-term, progress away from a quantifiably large risk of extinction for these stocks is paramount"). When returns and abundance levels are at historic lows, a slight increase for one or two years says little about a species survival or recovery.

The Court finds persuasive the evidence submitted by Plaintiffs and their aligned *amici* that FCRPS operations are harmful to the species. The 2020 BiOp itself acknowledges that the FCRPS operations contemplated in the Proposed Action will kill a substantial amount of the listed fish. 2020 BiOp at 1377-1412 (Incidental Take Statement). For some populations, the rate of slaughter is likely to be so high as to result in generational decline. Bowles Decl. ¶¶ 51-53. Thus, as the Court has held before, the Proposed Action is likely to "strongly contribute to the endangerment of the listed species and irreparable injury will occur if changes are not made." *NMFS VI*, 2005 WL 1398223, at *4; *see also NMFS VIII*, 2017 WL 1829588 at *5.

The Federal Defendants assert that FCRPS operations have changed, relying on recent increases in spill. But the 2026 Draft Fish Operations Plan ("FOP") reduces spill. *See, e.g.*, Bowles Reply Decl. Ex. 1, ECF 2624 at 55 (Fish Passage Center Memorandum, Review of draft Fish Operations Plan document, January 16, 2026) (explaining that "[s]pring and summer spill operations outlined in the Draft FOP are inconsistent with the 2020 NMFS BiOp and, in fact, are reductions from the 2020 NMFS BiOp"). Thus, absent a spill injunction order, the recent operational changes and the concomitant benefits to fish will disappear. *See, e.g.*, *id.* (describing that "Reduced spill under the Draft FOP will result in increased powerhouse passage (i.e., PITPH) and increased bypass encounters, which are associated with slower fish travel times, lower juvenile survivals, and lower smolt-to-adult returns (SARs)"). Moreover, even with increased spill, the FCRPS is still the number one contributor to fish mortality in the Interior

Columbia Basin. *See Rebuilding Report*, at 12 T.3 (ranking limiting factors to the listed salmonids, with the hydrosystem well in the lead).

The Federal Defendants also argue that Plaintiffs cannot request equitable relief because many factors harm salmonids, some Plaintiffs harvest salmon, and Oregon manages fisheries that take the listed species. The loss of listed species from other factors, however, is much less than the loss from the FCRPS operations. *See Rebuilding Report*, at 12. T.3. And the mere fact that Plaintiffs are challenging the biggest threat to the species while not challenging other threats does not doom their claim. *See NMFS IX*, 886 F.3d at 819 (stating that "a plaintiff 'need not further show that the action sought to be enjoined is the exclusive cause of the injury'" (quoting *M.R. v. Dreyfus*, 697 F.3d 706, 728 (9th Cir. 2012)); *League of Wilderness Defs./Blue Mountains Biodiversity Project v. Connaughton*, 752 F.3d 755, 765 (9th Cir. 2014) ("We have never made a rule that a plaintiff must challenge all related harms to maintain an ability to challenge the harm that it views as the most serious.").

The Federal Defendants further argue that the Court must find that the species will go extinct during the pendency of this lawsuit in order to grant preliminary relief. The Ninth Circuit, however, has expressly rejected this argument—the Court does "not need to find an extinction-level threat to the listed species in the short term." *NMFS IX*, 886 F.3d at 821. Nonetheless, the Court finds that the threats to the listed species are dire and immediate.

The Federal Defendants contend that Plaintiffs, as individuals, will not suffer irreparable harm and cannot claim generalized harm to the species. The Court rejected this argument in issuing the preliminary injunction in 2017, finding that Plaintiffs "ha[d] adequately shown how harm to the listed species will affect [Plaintiffs]." *NMFS VIII*, 2017 WL 1829588, at *5 n.7. The Ninth Circuit agreed, concluding that "plaintiffs have shown irreparable harm to their own

interests stemming from the irreparable harm to the listed species. For example, in support of its motion for the injunction, NWF submitted a declaration from Kevin Lewis that described his recreational and aesthetic pursuits on Idaho's rivers that depend on the health of listed salmonid populations." *NMFS IX*, 886 F.3d at 822.

Plaintiffs submitted here the same type of evidence accepted by the Ninth Circuit in *NMFS IX*. For example, Plaintiffs submitted the Declaration of Liz Hamilton, describing her recreational and aesthetic pursuits on the Columbia River that depend on the health of the listed salmonid populations. ECF 2528. Ms. Hamilton described her long history of fishing on the Columbia River, and noted her ongoing harm from reduced salmon, including with bringing her grandchildren to fish and being required to take multiple trips before they got their first catch due to reduced salmon in the river, and needing to stay longer on fishing trips (with the associated extra cost) when salmon abundance is low. She "connected her injuries to the anticipated irreparable injuries to salmonids from dam operations," *NMFS IX*, 886 F.3d at 822, by describing how operations are anticipated to reduce salmon populations and how fewer salmon make it difficult to fish.

Plaintiffs also submitted a declaration from Joseph Bogaard. ECF 2527. He explains that his family regularly boats, camps, and swims in and along the rivers within the Columbia Basin. He describes "the immense beauty and power of seeing adult salmon and steelhead returning from the ocean in search of their natal spawning gravels." Bogaard Decl. ¶ 8. He explains how he has watched tribal fishing and listened to stories about salmon from local residents. He describes how the loss of the salmonids in the Columbia Basin affect his enjoyment of the area and that these fish represent a "special and irreplaceable part of the fabric of the areas where I recreate."

Id. ¶ 9. He further notes that he used to fish but has not done so in years because of the decline in salmonid populations.

Oregon, as a sovereign, also is personally damaged by the potential loss of the listed and endangered species. "Wildlife is the property of the state." ORS 498.002(1). Oregon has a right to protect and defend the wildlife in its borders. Because the Court has found that the species are facing irreparable harm during the pendency of this litigation, Oregon's sovereign interest in the species suffices to show that they have a personal loss for purposes of injunctive relief. The Court rejects the Federal Defendants' argument that Plaintiffs have failed to establish harm to themselves.

Currently, the abundance of salmon and steelhead populations in the Columbia and Snake Rivers make them vulnerable to extinction. Further degradation of that abundance is irreparable harm. Defendants' Proposed Action not only fails to avoid that irreparable harm, but also directly contributes to it. Plaintiffs have met their burden to show irreparable harm.

3. The Balance of the Equities and the Public Interest

In cases under the ESA, these two *Winter* factors are treated differently. "Congress has spoken in the plainest of words, making it abundantly clear that the balance has been struck in favor of affording endangered species the highest of priorities[.]" *TVA*, 437 U.S. at 194. In the Ninth Circuit, generally in ESA cases, courts "do[] not consider the balance of equities and the public interest when deciding whether to issue preliminary injunctions under the ESA." *San Luis Obispo Coastkeeper v. Cnty. of San Luis Obispo*, 161 F.4th 590, 593 (9th Cir. 2025); *see also Cottonwood Env't L. Ctr. v. U.S. Forest Serv.*, 789 F.3d 1075, 1090 (9th Cir. 2015) (concluding that because Congress has "strip[ped] courts of at least some of their equitable discretion in determining whether injunctive relief is warranted," "courts do not have discretion to balance the parties' competing interests in ESA cases" (citing *TVA*, 437 U.S. at 185)); "In cases involving

the ESA, Congress removed from the courts their traditional equitable discretion in injunction proceedings of balancing the parties' competing interests." *NMFS VII*, 422 F.3d at 793-94 (quoting *Nat'l Wildlife Fed'n v. Burlington N. R.R.*, 23 F.3d 1508, 1511 (9th Cir. 1994)).

There is an exception, however, when there are competing interests of other endangered species. *San Luis Obispo Coastkeeper*, 161 F.4th at 600 ("[W]e hold that district courts retain their equitable discretion when considering a mandatory preliminary injunction under the ESA that could endanger other listed species. The exception to the traditional test, created in *TVA*, does not apply. The court must balance the equities and consider the public interest as to the other listed species."). Thus, the Court confines its analysis on balance of the equities and public interest to the pending motions' likely impact on endangered species.

As discussed above, Plaintiffs have demonstrated a likelihood of success on the merits. The dire situation for the 14 endangered and threatened populations of salmonids and smelt are well documented. Defendants and some *amici* point to some stronger returns for some populations. For the reasons discussed by Plaintiffs and their aligned *amici*, the Court does not find persuasive the evidence about the intermittent stronger returns for these few populations as support that the listed species are out of danger.

Plaintiffs request short term measures that might stem the slide into extinction. On the other side of the scale, the Federal Defendants have placed concerns about the injunction's impact on bull trout, another endangered species. ECF 2569 at 105-109. Simply weighing the number of species, the lone bull trout to the 14 listed species weighs in favor of protecting the many over the one. More importantly, the relief sought for the salmon and steelhead tracks the best practices articulated in this case's quarter-century-long record. The record about the potential impacts to bull trout is limited, deeply contested, and less well-established. The Court

also can infer from the bull trout's current existence that it has survived past dam operations that are similar to those that Plaintiffs now want the Federal Defendants to implement. Conversely, in the absence of injunctive relief, the Federal Defendants plan an approach to FCRPS operations that the available evidence shows will threaten the continued existence of many salmonid populations in the Columbia and Snake Rivers.

Consideration of another listed species does not require denial of requested relief. *San Luis Obispo Coastkeeper*, 161 F.4th at 601 (clarifying that "our holding does not require a district court to deny relief whenever another species might be affected"). The Court must determine "whether a mandatory preliminary injunction for the protection of one species is appropriate despite the risks to others." *Id.* Considering the potential risk to bull trout, the Court finds that the preliminary injunction here is warranted.

Even were the Court to expand the scope of its analysis on the balancing of the equities and the public interest, it would still find that these factors weigh heavily in favor of preliminary relief for two reasons. First, further harm to the listed species would be catastrophic to the tribes of the Columbia River Basin. The salmon and steelhead of the Columbia River are integral to the cultural, religious, social, and economic life of many of these tribes, "not much less necessary to [their existence] than the atmosphere they breathe[]." *United States v. Winans*, 198 U.S. 371, 381 (1905). The federal government "has charged itself with moral obligations of the highest responsibility and trust" to protect tribal treaty rights. *Seminole Nation v. United States*, 316 U.S. 286, 297 (1942). Those obligations extend to rights created by treaties with the Yakama, Umatilla, Warm Springs, and Nez Perce tribes, among others, respecting access to fish stocks in the Columbia River. *See, e.g.*, Treaty with the Yakamas, June 9, 1855, 12 Stat. 951; Treaty with the Tribes of Middle Oregon, June 25, 1855, 12 Stat. 963, 965; Treaty with the Wallawalla,

Cayuse, etc., June 9, 1855, 12 Stat. 945, 947; Treaty with the Nez Perces, June 11, 1855, 12 Stat. 957, 959. Those rights include not just "a fair share of the fish produced by the Columbia River system," *Sohappy v. Smith*, 302 F. Supp. 899, 911 (D. Or. 1969), but inherently also include the protection of listed fish against destruction so that they will be present for harvest. *See United States v. Washington*, 853 F.3d 946, 965 (9th Cir. 2017) (inferring from the treaties a promise that "the number of fish would always be sufficient to provide a 'moderate living' to the Tribes." (quoting *Washington v. Wa. State Com. Passenger Fishing Vessel Ass'n*, 443 U.S. 658, 686 (1979))).

Upholding the promise of these treaties is a vital public interest, not least because, like other treaties, they form part of the "supreme law of the land." *United States v. Forty-Three Gallons of Whiskey*, 93 U.S. 188, 196 (1876); *see also, e.g.*, *Oglala Sioux Tribe v. United States*, 674 F. Supp. 3d 635, 686 (D.S.D. 2023) (upholding treaty obligations to tribes "generally advances the public interest"); *Muckleshoot Indian Tribe v. Hall*, 698 F. Supp. 1504, 1516 (W.D. Wash. 1988) (enforcement of tribal treaty rights "is an important public interest"); *United States v. State of Mich.*, 471 F. Supp. 192, 267 (W.D. Mich. 1979) ("it continues to be in the national interest to observe and enforce treaty obligations owed to Indians."). Indeed, nothing less than the honor, reputation, and trust of the nation is at stake in that effort.

Second, Defendants' public interest arguments either lack merit or are outweighed by countervailing interests. The Federal Defendants contend that Plaintiffs' requested injunctive relief would negatively impact treaty-protected migratory birds, and that public health and financial interests support a rejection of preliminary relief. As for the birds, as discussed below, the Court does not grant Plaintiffs' requested non-operational measures with respect to the Caspian terns and double-crested cormorant. Similarly, the financial and logistical concerns that

the Federal Defendants articulate in their brief are moot, because the Court does not grant the non-operational components of the requested injunction regarding dam facilities.

Defendants also raise concerns relating to power system reliability, flood risk, transportation, irrigation, and availability of water supplies and clean drinking water. Many of those concerns appear ameliorated by the Court's imposition of an injunction at Minimum Irrigation Pool ("MIP"), instead of Plaintiffs' requested injunction at Minimum Operating Pool ("MOP"). Additionally, these concerns are belied by the reality of recent CRS operations. Since the stay of litigation, the Northwest Power and Conservation Council ("Council"), the organization responsible for assessing regional power demand and reliability, has found the regional power system to be reliable and anticipates that the system will continue to meet reliability standards for at least three more years. Hirsh Decl. ¶¶ 12-18. Moreover, the routine variances and adjustments that have helped to support that reliability will continue to be available to Federal Defendants under the injunction. So too would the emergency protocols previously used to prevent and mitigate flooding remain available to Federal Defendants. Federal Defendants' own BA suggests that the FCRPS operations at MOP for substantial portions of the year, ACE1067136-37, and thus operating at MIP should not create the problems feared by Defendants. The Court, therefore, would give more weight to the interests of the listed and endangered species even if the Court were able to balance those interests against other economic and social interests.

C. Conclusion on the Preliminary Injunction

Because they have shown that they are likely to succeed on the merits, that they will suffer irreparable harm in the absence of a preliminary injunction, and that the balance of the equities and public interest weigh in their favor, Plaintiffs have met their burden to show they are

entitled to preliminary injunctive relief. The Court thus grants Plaintiffs' motions for preliminary injunction. The Court turns to the specific relief requested relief, and grants that relief in part.

D. Tailored Injunctive Relief

Plaintiffs request a myriad of operational and non-operational preliminary relief, arguing that all of this relief is required during the pendency of this litigation to keep the listed species from sliding into extinction. "[I]n the context of the ESA, 'the test for determining if equitable relief is appropriate is whether an injunction is necessary to effectuate the congressional purpose behind the statute.'" *NMFS VII*, 422 F.3d at 795 (quoting *Biodiversity Legal Found. v. Badgley*, 309 F.3d 1166, 1177 (9th Cir. 2002)). The Court recognizes the dire situation these species are facing. The Court agrees that doing nothing during the pendency of this litigation would not effectuate the congressional purpose behind the ESA. The "basic purpose of the ESA [is] to protect endangered and threatened species and prevent their further decline." *Marbled Murrelet v. Babbitt*, 83 F.3d 1060, 1064 (9th Cir. 1996), *as amended on denial of reh'g* (June 26, 1996) (quoting *Forest Conservation Council v. Rosboro Lumber Co.*, 50 F.3d 781 (9th Cir. 1995).

This case has a long history of failed BiOps, Court intervention and monitoring, and Federal Defendants' attempts to "manipulate" variables and engage in "sleight of hand" conduct to avoid making hard decisions and face the consequences of its actions. *See NMFS III*, 524 F.3d at 933. It appears that the 2020 BiOp and 2020 FEIS follow this disappointing history of government avoidance and manipulation instead of sincere efforts at solving the problem and genuinely remediating the harm. And the government has shown with its draft 2026 FOP that it intends to make significant changes to FCRPS operations in the wrong direction. It proposes spill below the level proposed in the 2020 BiOp, changing its position about the benefits of spill and altering how the dams have been operated over the last several years to the detriment of the listed

species. Nonetheless, the Court must craft an injunction that is narrowly tailored to address the harm, that works as a *preliminary* injunction, and that falls within the Court's equitable authority. The Court turns to each of the types of relief requested by Plaintiffs. The Court separately will enter the injunction order, but here discusses what requested relief the Court will grant and why.[13]

1. Spill

The Court in the past has ordered spill, which the Ninth Circuit has affirmed. *See NMFS VI*, *NMVS VII*, *NMVS VIII*, and *NMFS IX*. The Court continues to find that it has authority to order spill. Spill offers immediate benefit to the listed species and is appropriate for preliminary injunctive relief. The evidence submitted by the Federal Defendants challenging the benefits of spill primarily was created for this litigation and is contrary to the established scientific evidence in the record. The Court gives it little weight.

Plaintiffs ask for spring spill at the same levels that were implemented in 2024 and 2025, except at John Day. *See* Corrected Hesse Decl., ECF 2541 at 41-46 (setting out in Tables 1-4 Plaintiffs' requested spill compared to spill levels previously implemented). For John Day, Plaintiffs request the level of spill that was applied for eight hours at night to be applied for the full 24 hours. The Court accepts this requested spill as reasonable.

For summer spill, Plaintiffs ask for the same level of spill implemented in 2024 and 2025, with the exception of John Day and Ice Harbor. Plaintiffs ask for more spill at these dams. Intervenor-Defendants request lower spill for Ice Harbor and John Day, to match the 2025 FOP. From Mr. Hesse's chart showing where Plaintiffs' spill levels previously have been

[13] Unless specifically discussed herein, the Court has considered and rejected objections and suggested revisions raised by Defendants.

implemented, these two spill levels derive from the 2018 FOP, but with alterations. In the 2018 FOP, the spill levels at Ice Harbor and John Day alternated. Plaintiffs take the higher spill level and seek to continue it 24/7. Thus, these spill levels have not previously been implemented. The Court accepts this proposed change by Intervenor-Defendants and adopts the 2025 FOP spill level for Ice Harbor and John Day.

Intervenor-Defendants also request to reduce spill in August, when fewer fish are migrating, as was done in the 2025 FOP. Although this may be a reasonable request if the benefit to fish is low and need for water for other uses is high, the Federal Defendants agreed in the MOU to operate the dams for years maintaining unchanged summer spill levels from June through July 31st. *See* ECF 2450-1 at 86-87. Those spill levels are identical to the levels being ordered by the Court. Additionally, previous summer spill orders maintained the same level of spill through August 31st. *See* ECF 1015 at 21-22. Thus, the Court grants the full summer spill duration as requested by Plaintiffs, without prejudice to any defendant to seek modification if problems arise due to spill levels in August.

For fall and winter spill, Plaintiffs request more spill, spill for longer hours, and spill for more days, in various combination, at the dams. For the reasons articulated by Plaintiffs, *see, e.g.*, Bowles Decl. ¶¶ 79-104, the Court finds that expanding fall and winter spill will provide immediate benefit to the listed species.

The Court builds into the injunction flexibility for the Action Agencies to adjust spills for emergency power generation and transportation needs. The Court is unpersuaded by arguments that spill will create various catastrophic results. Defendants have raised these concerns each time spill is litigated without them coming to fruition. The majority of the spill has been implemented over the years without such negative repercussions, and the Court does not

anticipate such calamities will ensue from the current spill order. The Court grants Plaintiffs requested spill as modified.

2. Reservoir Levels

Plaintiffs request specific reservoir forebay levels, primarily at minimum operating pools ("MOP"). Plaintiffs describe that reducing reservoir levels to MOP would result in immediate benefit to salmonids because it decreases travel time of juveniles. Indeed, NMFS has calculated that reducing reservoir levels could decrease travel time by 2-18 hours per dam. *See* Declaration of Daniel ¶ 36 (ECF 2573). Defendants object, arguing that mandatory continuous operations at MOP will result in serious harm to power generation, transportation, and irrigation. These arguments are somewhat hollow, given that the Federal Defendants *agreed* in the MOU to operate the Lower Granite, Little Goose, Lower Monumental, and Ice Harbor dams at MOP for years. *See* ECF 2450-1 at 89-90. And the Federal Defendants have actually operated the lower Snake River dams at MOP for years. *See* Bowles Decl. ¶ 117.

Plaintiffs contend that the 2020 BiOp allows higher reservoir levels that are a rollback from previous BiOps and are detrimental to the listed species. *See* ECF 2530 at 21-22; ECF 2526 at 57-58. Given the seriousness of the harm facing the listed species, ensuring that reservoir levels are maintained in a manner that prioritizes the species is a reasonable request for preliminary relief. Defendants, however, argue that the levels requested by Plaintiffs will result in significant harm to power generation, transportation, and irrigation.

To ensure that reservoir levels do not cause unforeseen negative consequences, the Court orders reservoir levels at the 2025 operating levels. The Federal Defendants successfully operated the dams at those levels and thus all parties can be assured of the viability of the operations for power generation, transportation, and irrigation. Additionally, the Court includes flexibility for the Action Agencies to deviate from these levels for transportation and power

generation emergencies. These levels are higher than what Plaintiffs request, but lower than what are allowed in the 2020 BiOp. They provide additional protection for the species while minimizing unintended negative consequences. The Court declines at this stage Plaintiffs' request to order the Federal Defendants to study MOP reservoir levels at John Day. That does not preclude the Federal Defendants from doing so, it simply is not required as part of this injunction.

3. Infrastructure Repair and Maintenance

Plaintiffs ask the Court to order the Federal Defendants to complete specific dam infrastructure repair and maintenance projects at several of the dams, as well as infrastructure projects aimed at benefitting the Tucannon River spring Chinook. Plaintiffs argue that these projects are vital to reducing the mortality caused by the FCRPS, and that the Federal Defendants have unreasonably delayed implementing the projects to the detriment of the species. Plaintiffs contend that given the dire situation of the species, ordering the Federal Defendants to engage in the most critical projects is essential.

The Court declines to order the requested repair and maintenance projects. Though Plaintiffs make compelling arguments as to the long-term necessity of these projects, this request is more appropriate for final relief rather than preliminary relief. The time horizon on the requested repairs extends far into the future, with benefits likely not reaped until future seasons, possibly even after a final decision on the merits of this case. That sort of distant relief is not calibrated to address the imminent harms for which preliminary injunctions are intended. *See State of Conn. v. Com. of Mass.*, 282 U.S. 660, 674 (1931) (holding that preliminary injunctions "will not be granted against something merely feared as liable to occur at some indefinite time in the future.").

4. Remaining Non-Operational Conservation Measures

Plaintiffs ask the Court to order Federal Defendants to conduct a range of additional non-operational conservation measures:

- Avian and piscine predation reduction, including measures to relocate or remove a double-crested cormorant colony nesting on the Astoria-Megler Bridge, Blalock Island Caspian terns and gulls, and non-native piscine species.
- Collection and transportation of steelhead kelt from Snake River tributary weirs and Lower Granite, Little Goods, and Lower Monumental Dams, to the Nez Perce Tribal Hatchery for reconditioning.
- Maximize adult-trap-and-transport operations of Snake River Sockeye by expanding operation of the Lower Granite Dam trap during migration season, targeting 25 to 50 percent of the adult sockeye return for collection, providing adult sockeye holding ponds at the Dworshak Hatchery, and collaborating with the Nez Perce Tribe to develop a Hatchery and Genetic Management Plan.

The Court declines to order the above requested non-operational conservation measures. "A preliminary injunction ordering Defendants to do something they said that are already going to do is unnecessary." *Elko, Inc. v. Peters*, 2022 WL 256975, at *7 (D. Nev. Jan. 27, 2022). Given the rule that preliminary injunctions should be narrowly tailored to that which is "necessary to effectuate the congressional purpose" behind the ESA, *NMFS VIII*, 422 F.3d at 795, and this Court's previous admonition that "[c]ourts should not micromanage an agency's procedures under the guise of judicial review", *Or. Nat. Desert Ass'n v. U.S. Forest Serv.*, 2007 WL 1072112, at *5 (D. Or. Apr. 3, 2007), it is prudent in the instant case to avoid unnecessary

mandatory preliminary injunctions. The 2020 BiOp already contains measures similar to those that Plaintiffs request, including:

- Avian predation management, including of Caspian terns, double-breasted cormorants, and gulls. *See* 2020 BiOp Appx. B.
- Non-native piscine predation control efforts. *See id.* at 696-702.
- Continued collection, transportation, and reconditioning of kelt at the Nez Perce hatchery. *See id.* at 426.
- Continued transportation efforts for Snake River sockeye salmon. *See id.* at 471-76.

Though these measures are not *exactly* what Plaintiffs request, they generally represent an effort to address the problems about which Plaintiffs are concerned via similar means. The Court will not order the Action Agencies to carry out actions they already plans to carry out, or to carry out similar actions. Understanding the importance of these non-operational measures to the survival of the listed species, however, the Court *does* order quarterly reporting to the Court on progress made with respect to its commitments on predation reduction, Snake River steelhead kelt transportation and reconditioning, and Snake River Sockeye transportation efforts. Should these reports demonstrate operations insufficient to enable the survival of and eventually restore the listed species, Plaintiffs have leave to refile on an expedited basis for preliminary injunctive relief.

E. Stay Pending Appeal

Defendants request a stay pending appeal. *See* ECF 2650. "A stay is 'an exercise of judicial discretion,' which should be issued 'dependent upon the circumstances of the particular case.'" *Manrique v. Kolc*, 65 F.4th 1037, 1040 (9th Cir. 2023) (quoting *Nken v. Holder*, 556

U.S. 418, 433 (2009)). The party requesting the stay "bears the burden of showing that the circumstances justify an exercise of that discretion" because "[a] stay is not a matter of right, even if irreparable injury might otherwise result." *Nken*, 556 U.S. at 433-34. To consider the appropriateness of a stay, the Court should "balance the relative equities," *Leiva-Perez v. Holder*, 640 F.3d 962, 965 (9th Cir. 2011) (per curiam), by considering four factors:

> (1) whether the stay applicant has made a strong showing that he is likely to succeed on the merits; (2) whether the applicant will be irreparably injured absent a stay; (3) whether issuance of the stay will substantially injure the other parties interested in the proceeding; and (4) where the public interest lies.

Nken, 556 U.S. at 434 (*quoting Hilton v. Braunskill*, 481 U.S. 770, 776 (1987)).

There is "substantial overlap" between the stay factors and "the factors governing preliminary injunctions." *See id.* Just as the Court concludes that Plaintiffs are likely to succeed on the merits of their claims for purposes of the preliminary injunction, it concludes that the Federal Defendants are unlikely to succeed on the merits for purposes of the stay. The second stay factor does not weigh in the Federal Defendants' favor because the relief the Court grants—pertaining only to spill and reservoir levels—is narrowly tailored and essentially maintains the *status quo*. The Federal Defendants have, for years, maintained a safe and reliable power system and dam operations with the nearly the same spill levels as ordered here, and with the same reservoir levels from 2025. "The first two factors of the traditional standard are the most critical," *id.* at 434, so the Federal Defendants' failures of proof here doom their request for a stay pending appeal.

The third and fourth stay factors also do not weigh in the government's favor. These factors do not merge when the government is the party seeking a stay. *See id.* at 435 ("These factors merge when the Government is the *opposing* party" (emphasis added)). Staying the injunction pending appeal poses a significant risk that the government will be unable to

implement *any* protective measures during 2026, causing significant harm to the species. Finally, as explained, the public interest always weighs in favor of protecting endangered species.

CONCLUSION

The Court GRANTS Plaintiffs' Motion for Preliminary Injunction, ECF 2526, and Intervenor-Plaintiff Oregon's Motion for Preliminary Injunction, ECF 2530, and GRANTS IN PART and DENIES IN PART their requested relief, as set forth in a separate order titled "Amended Preliminary Injunction Order."

IT IS SO ORDERED.

DATED this 2nd day of March, 2026.

Michael H. Simon
United States District Judge

EXHIBIT 115

IN THE UNITED STATES DISTRICT COURT

FOR THE DISTRICT OF OREGON

NATIONAL WILDLIFE FEDERATION, et al.,

Plaintiffs,

and

STATE OF OREGON, et al.,

Intervenor-Plaintiffs,

v.

NATIONAL MARINE FISHERIES SERVICE, et al.,

Defendants,

and

PUBLIC POWER COUNCIL, et al.,

Intervenor-Defendants.

Case No. 3:01-cv-640-SI

DECLARATION OF RACHEL DIBBLE IN SUPPORT OF FEDERAL DEFENDANTS' OPPOSITION TO PLAINTIFFS' MOTIONS FOR A PRELIMINARY INJUNCTION

I, Rachel Dibble, declare and state as follows:

1. I have been employed with the Bonneville Power Administration ("Bonneville") since 2008. Bonneville is a federal power marketing administration within the Department of Energy responsible for marketing and distributing power generated by the Federal Columbia River Power System ("FCRPS"),[1] which includes the fourteen federal dams at issue in this litigation that are operated as a coordinated water management system (referred to hereinafter as "the Columbia River System" or "CRS"). Bonneville also operates and maintains the federal high voltage transmission system in the Pacific Northwest, which interconnects and integrates electric power generated at the FCRPS projects, as well as non-federal power generators, to the regional transmission grid.

2. I hold a master's degree in business administration from Arizona State University and have a Bachelor of Arts in Economics and Business from Westmont College.

3. I am the Vice President of Generation Asset Management within Bonneville's Power Services organization and have been in this position since May 2025. Generation Asset Management plans and executes financial investments in the power assets of the FCRPS; plans and executes long-term, mid-term, short-term, and real-time operations for the coordinated system operations of the FCRPS to meet combined power and non-power requirements; coordinates and implements U.S. rights and responsibilities under the Columbia River Treaty ("Treaty") with Canada in coordination with the U.S. Army Corps of Engineers (Corps); analyzes and coordinates fish operations with regional stakeholders; and implements Preference Customer contracts[2] based on the operational capability of the FCRPS used to supply firm power

[1] The FCRPS includes 31 multi-purpose dam and reservoir projects in the Pacific Northwest region, constructed and operated by the U.S. Army Corps of Engineers ("Corps") and the Bureau of Reclamation ("Reclamation"), from which Bonneville markets and distributes power using the federal transmission system. This includes the 14 Columbia River System (CRS) projects. In this declaration, FCRPS is used when there could be effects to the broader 31 projects while CRS is used if the effects would be limited to the 14 CRS projects.

[2] Bonneville's preference customers are statutorily defined as "public bodies and cooperatives." 16 U.S.C. § 832c(a). They range from small rural electric cooperatives to large municipal

to meet Bonneville's statutory and long-term power sales contract obligation. Prior to this position, I was the Vice President of Bulk Marketing for over three years, beginning in January 2022. My responsibilities in Bulk Marketing included real time, day ahead and forward energy trading, long term generation purchases and sales, power scheduling and contract administration and market analysis, pricing and policy. In 2020 to 2022, I led several public processes in the Business Transformation Office, exploring and compiling the record for the Administrator's final decisions on Western Energy Imbalance Market ("EIM")[3] and Western Resource Adequacy Program ("WRAP")[4] participation. I also managed multiple groups in Bonneville's Transmission Marketing and Sales organization from 2014 to 2020, where I was responsible for the content, implementation and public processes to update Bonneville's Open Access Transmission Tariff ("OATT" or "Tariff")[5] and collaborate with Transmission Operations and Transmission Planning teams to ensure the commercial rules in the OATT are consistent with the operations and planning for the transmission system.

4. I have reviewed the Motions for Preliminary Injunction ("PI") filed with this Court on October 14, 2025, by the National Wildlife Federation ("NWF") (ECF 2526), the State of Oregon (ECF 2530) and the Proposed Order (ECF No. 2530-2) ("Prop. Order") as supported by the Nez Perce Tribe (ECF 2536), the State of Washington (ECF 2533), and the Yakama Nation (ECF 2537), and their respective declarations. I also have consulted with experts from Bonneville and other federal agencies, including the Corps, the National Marine Fisheries

utilities. These customers contract with Bonneville pursuant to their priority claim on federal power generation.

[3] On May 3, 2022, Bonneville began participation in the EIM. A summary of this action can be accessed at www.bpa.gov/learn-and-participate/projects/energy-imbalance-market.

[4] WRAP is the first regional reliability planning and compliance program in the history of the West. Bonneville's first fully operational and compliance-binding season within WRAP is scheduled to be winter 2027-2028. For additional details refer to www.bpa.gov/learn-and-participate/projects/western-resource-adequacy-program.

[5] OATT defines the terms and conditions of point-to-point and network integration transmission services, ancillary services, and generator interconnections offered by BPA Transmission Services. For additional details refer to www.bpa.gov/energy-and-services/transmission/tariff.

Service ("NMFS"), and the U.S. Fish and Wildlife Service.

I. Introduction and Background

5. In this declaration, I address the following topics: (1) Bonneville's statutory obligations and multiple public purposes; (2) the current state of the Pacific Northwest power system and power adequacy, (3) risks associated with the implementation of Plaintiff's operational requests in the Prop. Order at the CRS projects on the lower Snake and lower Columbia rivers as compared to the operations in the Draft 2026 Fish Passage Plan (FPP), including Appendix E Fish Operations Plan ("Draft 2026 FOP"), and the Final 2026 Water Management Plan, including risks to electric reliability on the region's high voltage transmission system, power production, and Bonneville's ability to meet its Treaty, statutory and contractual obligations; (4) modeled (or expected) financial impacts to Bonneville as a result of implementation of the Prop. Order; and (5) the infrastructure requests in the Prop. Order through the lens of how this work is planned, funded and coordinated between Bonneville and the Corps.

II. Bonneville's Statutory Obligations and Multiple Public Missions

6. By statute, Bonneville operates as a not-for-profit entity, selling cost-based electrical power and transmission services to benefit the Pacific Northwest, especially the public bodies and cooperatives which serve domestic and rural consumers. To supply power and provide transmission services under its four enabling statutes,[6] Bonneville must balance multiple public duties and purposes, including ensuring the Pacific Northwest has an adequate, efficient, economical and reliable power supply, [7] and consistent with the program developed by the

[6] 16 U.S.C. §§ 832–832m (Bonneville Project Act); 16 U.S.C. §§ 837–837h (Regional Preference Act); 16 U.S.C. §§ 838–838l (Federal Columbia River Transmission System Act); 16 U.S.C. §§ 839–839h (Pacific Northwest Electric Power Planning and Conservation Act, commonly known as the Northwest Power Act).

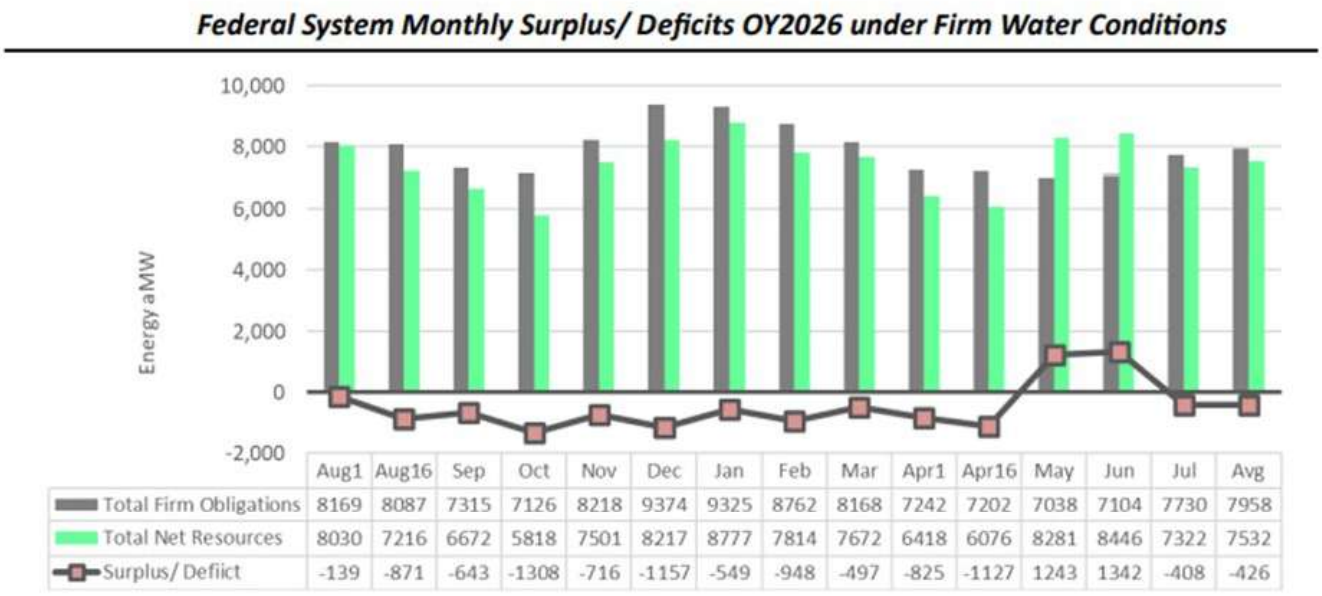
[7] *See Power Planning*, NW. POWER & CONSERVATION COUNCIL, www.nwcouncil.org/energy/ (last visited Nov. 18, 2025). The Northwest Power Act also requires the Council to develop a plan to ensure adequate, efficient, economical, and reliable power supply for the region; currently, the Council is developing a new draft plan.

Northwest Power and Conservation Council, protecting, mitigating, and enhancing fish and wildlife in the Columbia River basin that are affected by the development and operations of the federal dam and reservoir projects from which Bonneville markets power.

7. Bonneville is required to serve its customers' electricity load[8] reliably; these requirements are also described in the 2025 Declaration of Bartholomew A. McManus ("McManus Decl.") ¶ 6 and the 2025 Declaration of Audrey Stevenson ("Stevenson Decl.") at ¶¶ 6-9. These include customers throughout the Pacific Northwest from military bases, major cities and major airports, tribal nations and rural communities. In addition, Bonneville provides back up power to the Columbia Generating Station, a nuclear plant in the State of Washington. This back up power is critical for returning the nuclear plant to operation after an outage as discussed in Stevenson Decl. at ¶¶ 17 and 33.

8. Given these load requirements, Bonneville must react to the availability of water relative to our load obligations. Figure 1 shows Bonneville's monthly load obligations (gray bars) and the generation from the firm water conditions (green bars). Looking at these load obligations by month under firm water conditions, the Federal system generally shows larger energy deficits across the winter and early spring periods until spring runoff starts, which then turns to energy surplus in May and June (Figure 1). It is Bonneville's obligation to make up the differences between the gray and green bars to avoid disruptions to meeting load obligations when Bonneville experiences an energy deficit.

[8] "Load" is used throughout to refer to energy demand.



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
Total Firm Obligations	8169	8087	7315	7126	8218	9374	9325	8762	8168	7242	7202	7038	7104	7730	7958
Total Net Resources	8030	7216	6672	5818	7501	8217	8777	7814	7672	6418	6076	8281	8446	7322	7532
Surplus/ Defict	-139	-871	-643	-1308	-716	-1157	-549	-948	-497	-825	-1127	1243	1342	-408	-426

Figure 1: Chart from Bonneville Power Administration 2025 White Book[9] illustrating monthly energy surplus and deficit, where the gray bars are the monthly load forecast, and the green bars are forecasted generation with the shape coming from the firm water (10th percentile) for hydropower generation.

9. Unlike most federal agencies, Bonneville does not receive annual congressional appropriations; instead, the agency is self-financed from revenues received from the sale of power and transmission services. Bonneville utilizes this revenue to not only pay for the continuing costs associated with its statutory obligation (including purchases of power and transmission, fish and wildlife mitigation, and maintenance of generation and transmission facilities) but also to pay for the power share[10] of FCRPS costs.[11] Bonneville pays for this power share through either repayment to the United States Treasury ("Treasury") for the power share of appropriations[12] tied to the original and ongoing federal investments[13] used to construct and

[9] BONNEVILLE POWER ADMINISTRATION, 2025 PACIFIC NORTHWEST LOAD AND RESOURCES STUDY (May 2025) ("2025 White Book"), 23, available at www.bpa.gov/-/media/Aep/power/white-book/2025-whitebook.pdf.
[10] *See* 2017 Declaration of Kieran Connolly, Bonneville Power Administration in Support of Federal Defendants' Combined Opposition to Motions for Injunctive Relief, ECF 2145, ¶ 6, FN 7 [hereinafter "2017 Connolly Decl."].
[11] *Id.* ¶ 6.
[12] *Id.*
[13] In addition to the original investment costs of the FCRPS used to construct the dams, the

maintain the FCRPS or directly to the Corps and Reclamation.[14] This funding process is described in more detail in Section VII. Infrastructure Repair and Maintenance Injunction (¶¶ 78-93). The Bonneville Administrator must operate the agency in a manner that allows it to recover its costs "in accordance with sound business principles."[15] This includes the objectives of setting the lowest possible rates for the sale of power and transmission services,[16] while enabling Bonneville to make timely repayments to the Treasury.

10. Bonneville must also fulfill multiple public purposes for the benefit of the Pacific Northwest. Bonneville accomplishes these missions through operation of the transmission system and managing the electrical energy and capacity of the multiple purpose CRS projects. Bonneville must do this in a coordinated manner with the Corps and Reclamation. These agencies have been tasked with operating the 14 projects that make up the CRS as a coordinated water management system for numerous authorized purposes in addition to power generation, including flood risk management, navigation, fish and wildlife conservation, irrigation, water supply, and recreation.[17] The operation, maintenance and configuration of the 14 CRS projects was analyzed in the 2020 Columbia River System Operations Final Environmental Impact Statement[18] and the Selected Alternative was documented in the Record of Decision ("CRSO EIS ROD") [ACE000339656]. Of these fourteen projects, the projects on the lower Snake and lower Columbia rivers are generally run of river projects (each reservoir has limited storage

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Corps and Reclamation may receive congressional appropriations that cover costs including the power share for investment or maintenance activities tied to the FCRPS. Bonneville's Treasury payment also includes repayment of these costs.

[14] In the Bonneville Project Act of 1937 and the Energy Policy Act of 1992, Congress authorized Bonneville to fund the power share directly to the Corps and Reclamation, a funding structure known as Direct Funding. *See* 2017 Connolly Decl. ¶ 38.

[15] 16 U.S.C. § 839e(a)(1); see also 16 U.S.C. §§ 825s, 838g.

[16] 16 USC § 838g.

[17] *See* U.S. ARMY CORPS OF ENG'RS, BUREAU OF RECLAMATION & BONNEVILLE POWER ADMIN., COLUMBIA RIVER SYSTEM OPERATIONS ENVIRONMENTAL IMPACT STATEMENT RECORD OF DECISION (2020) (hereinafter "CRSO EIS ROD"), § 2.4.

[18] U.S. ARMY CORPS OF ENG'RS, BUREAU OF RECLAMATION & BONNEVILLE POWER ADMIN., COLUMBIA RIVER SYSTEM OPERATIONS FINAL ENVIRONMENTAL IMPACT STATEMENT (2020) [ACE001056027] (hereinafter "2020 CRSO Final EIS").

capabilities).[19] Managing this interconnected and cascading system introduces multiple hydraulic challenges that would be magnified as a function of implementing the Prop. Order and the associated decrease in operating flexibility, which I discuss in ¶ 53.

11. The interdependence of each project requires constant coordination.[20] The issues involved in operating the interconnected multiple purpose projects on the lower Snake and lower Columbia rivers are detailed in the 2025 Declaration of Aaron W. Marshall ("Marshall Decl.") ¶¶ 9, 11, 15. For my short-term and real-time scheduling staff, some key issues for delivering the contracted energy and transmission stability hinges on how the CRS is managed for operational and flow uncertainties. Some of these uncertainties include events like rapid increases or decreases in water outflows at a single dam that will affect the downstream project forebay or flow changes, which can lead to hydraulic "bouncing," as illustrated in Figure 2. Additionally, there are numerous constraints Bonneville must operate within, such as reservoir operating ranges above minimum operating pool elevations for irrigation and water supply withdrawals in specific reservoirs, and safe navigation that dictates forebay and tailrace elevations at multiple projects.[21]

[19] *Id.* at 1-29. John Day is technically a storage project, during fish passage season the project is operated in Minimum Irrigation Pool range which removes the storage capacity to the extent the project must be operated as run-of-river.
[20] A constantly staffed position (which Bonneville employees call "the Hydro Desk") within Bonneville plans and makes requests to the Corps or Reclamation to implement the generation request and spill request at each of these projects in a carefully coordinated manner to ensure the respective inflows and outflows at the projects are working in concert to meet all power and non-power requirements. The Hydro Desk is typically planning operations over the next 12 to 24 hours, considering forecasted regional loads, current outages, and operational requirements that may require a long lead time to plan and implement.
[21] Marshall Decl. ¶¶ 22, 24.

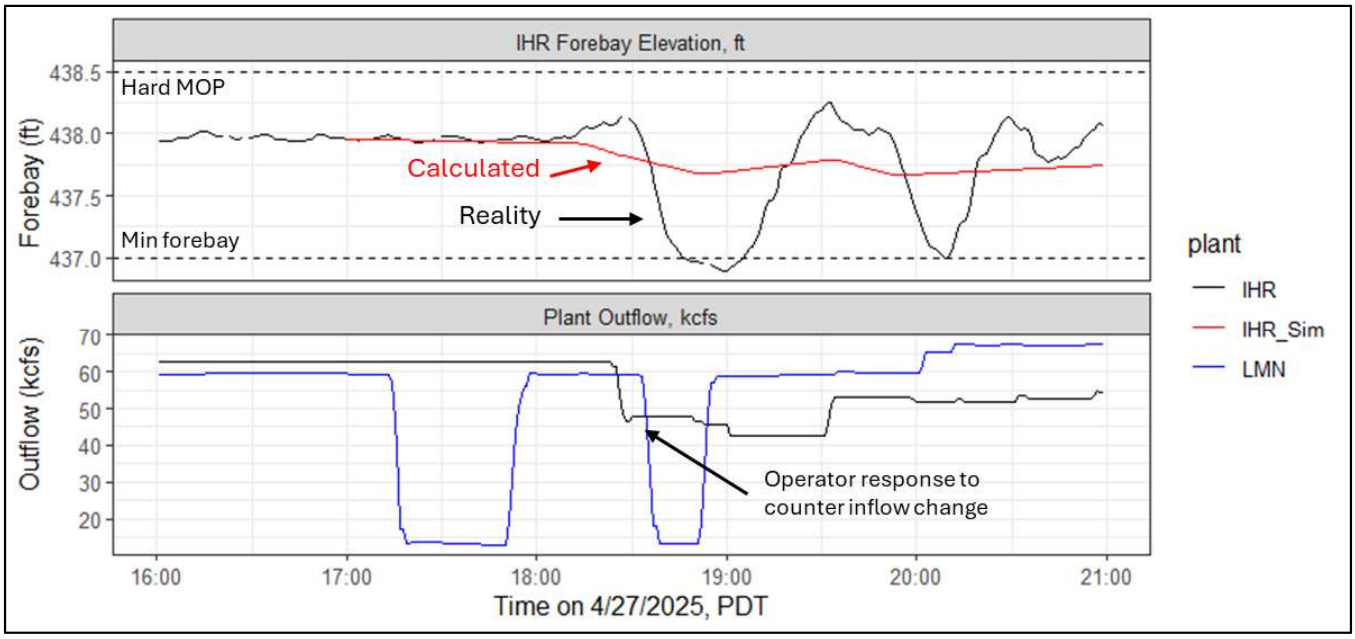


Figure 2: Demonstration of Ice Harbor Dam forebay elevation "bounce" observed on April 27, 2025, triggered by a temporary reduction in spill at Lower Monumental Dam for navigation safety.[22] Dams are referred to as "plants" in this figure.
Top: Forebay elevation averaged in one minute intervals at Ice Harbor Dam (*observed* represented by black line) and calculated forebay elevation (*expected elevation*[23] represented by red line) between 17:00 and 21:00.
Bottom: Outflows (kcfs) from Ice Harbor Dam and the upstream project, Lower Monumental Dam.

[22] Figure 2 illustrates an example of reservoir "bounce" at Ice Harbor Dam's reservoir with temporary decreases in spill for navigation safety. In this example, Lower Monumental Dam outflows decreased at 17:15 to minimum flows for 45 minutes, and again at 18:30 for 30 minutes. The lag time between Lower Monumental and Ice Harbor dams is approximately one hour, with operators planning decreases in outflows at Ice Harbor Dam to counter the inflow changes and keep Ice Harbor Dam reservoir within the hard forebay constraints of 1.5 feet. The much larger response in the actual forebay is the manifestation of the forebay "bounce" common in the management of existing reservoirs. The first "bounce" dropped the forebay 1.2 feet in 30 minutes and violated the minimum forebay elevation of 437 feet at 19:00.
[23] The "expected elevation" is the calculated change in Ice Harbor Dam forebay elevation was based on inflows and outflows.

III. Current State of the Pacific Northwest Power System and Resource Adequacy

12. The Pacific Northwest regional power system experienced numerous challenges in the past few decades including the 2000/2001 west coast energy crisis, and several periods of resource adequacy concerns from consecutive dry water years. These events were caused in large part by lack of water available for hydropower generation. The current outlook for the Pacific Northwest regional power system is forecasted to experience widespread resource adequacy problems in the coming years due to factors such as massive load growth from data centers and electrification. [24]

13. Moreover, the amount of available generation is not projected to keep pace with regional demand. In a presentation given to the state of Washington Utilities and Transportation Commission and Department of Commerce, the consulting firm Energy and Environmental Economics ("E3") shared its findings that "Accelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to 9 gigawatts ("GW") by 2030."[25] E3 also noted that "9 GW is approximately the load of the State of Oregon."[26] The Pacific Northwest Utilities Conference Committee ("PNUCC") also highlighted the growth in loads and difficulties of the region to add generation resources fast enough in PNUCC's 2025 regional forecast. [27] This report focuses on load increases from higher-than-expected need for air conditioning, electric vehicles adoption, and construction and operation of data centers. PNUCC forecasts a projected load-growth increase of more than 30 percent by 2034.[28]

14. Even if average load levels had not changed dramatically in the past few years, there

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[24] McManus Decl. ¶¶ 14-15.
[25] E3, RESOURCE ADEQUACY AND THE ENERGY TRANSITION IN THE PACIFIC NORTHWEST: PHASE 1 RESULTS, 2, available at www.utc.wa.gov/sites/default/files/2025-10/Revised V3 E3 Presentation RA Study September 22 WA RA Meeting.pdf (last visited Dec. 10, 2025).
[26] *Id*.
[27] PAC. NW. UTILS. CONF. COMM., NORTHWEST REGIONAL FORECAST OF POWER LOADS AND RESOURCES (2025), available at www.pnucc.org/wp-content/uploads/2025-PNUCC-Northwest-Regional-Forecast-final.pdf.
[28] *Id*. at 5.

continues to be continuously growing peak load events that threaten reliability, especially in the winter and summer seasons, often due to extreme weather. Recent examples of extreme weather events, risks and added strain on the conveyance of reliable electricity to Bonneville's customers are included in Stevenson Decl. ¶¶ 28-34.

15. A specific recent example of an extreme weather event in winter is the January 2024 cold snap where "[a] *cold front moved into the Northwest on January 12, pushing temperatures down and demand up across the region. Several load-serving entities set new peak demand records over the weekend. Many of those entities set their previous record highs a little over a year ago in December 2022*."[29] During this 2024 cold snap, Bonneville's system hit a peak demand of 11,396 megawatts ("MW") between 11 a.m. and noon on January 13, 2024; a level not seen in the decades since the region's aluminum smelters closed. This event highlights that the regional loads are growing and that generation availability and water availability[30] are key to managing reliability through extreme weather.

16. Additionally, during the summer of 2021 the Pacific Northwest experienced three heat waves. The most intense heat occurred between June 26-28, 2021, where the region saw unprecedented temperatures with the highest being recorded in Lytton, British Columbia, Canada at 121°F. Regional peak loads reached 81,636 MW on June 28, 2021, just shy of the region's record load of 81,959 MW recorded on August 17, 2020.[31] The summer continued with additional heat waves on July 29-31, 2021, and then again August 12-14, 2021. The summer of 2021 highlights the energy demands that can occur during all summer months.

IV. Risks to Public Safety and Security Associated with the Prop. Order to Change System Operations Beginning in 2026

[29] Dan Catchpole et al., *Cold Snap Strains Northwest Utilities as Energy Prices Surge*, NEWSDATA (Jan. 26, 2024), www.newsdata.com/clearing_up/supply_and_demand/cold-snap-strains-northwest-utilities-as-energy-prices-surge/article_a6100c06-b6ef-11ee-ab37-131425b0214e.html.

[30] For hydropower generation, water availability is assessed as water that can be routed through turbines, either water inflowing to the project, or access to stored water in the forebay.

[31] *See also* Stevenson Decl. ¶ 30.

17. In this section of my declaration, I describe the feasibility issues of, risks associated with, and key considerations my staff and I have identified related to the responsible management of the integrated federal power and transmission system, if the Court orders the implementation of the Prop. Order in general and on such short notice.

A. Reliance on "Emergency Operations" is Misplaced

18. Under existing operations, there are Emergency Protocols the Agencies implement when needed to maintain system reliability and stability.[32] However, the Prop. Order does not clearly state that these Emergency Protocols would continue to apply, including those that allow for adjustments in hydropower generation to support power system reliability beyond voluntary spill reductions for reserves.[33] This lack of clarity is particularly problematic because the Prop. Order's requested spring spill operations and the minimum operating reservoir ranges will limit the flexibility required to safely operate the CRS. Imposing the Plaintiffs' proposed operations greatly limits the Agencies' ability to identify and implement possible solutions to help protect the reliability of the integrated power and transmission system and pushes Bonneville closer to, and likely over the threshold, where the usage of the Emergency Protocols becomes more common.[34] Bonneville staff coordinate with the other federal agencies as well as regional sovereign fish and wildlife managers through the Technical Management Team ("TMT"), to

[32] BONNEVILLE POWER ADMIN., BUREAU OF RECLAMATION & U.S. ARMY CORPS OF ENG'RS, Water Management Plan – 2026, app. 1, attach. 1 (2025). https://public.crohms.org/tmt/documents/wmp/2026/Appendix/Appendix_1_Emergency_Protocols_20251202.pdf.

[33] The Prop. Order refers to the annual Water Management Plan only regarding spill operations: "Beginning in 2026, Water Management Plans and FOPs must require, before curtailing voluntary spill to help carry energy reserves (e.g., as outlined in the 2025 FOP), due diligence implementation of preemptive actions, as well as a declaration of power system emergency and/or spill variance reporting." Prop. Order at 7. The annual Water Management Plan is where the Emergency Protocols are described. *See, e.g.,* BONNEVILLE POWER ADMIN., BUREAU OF RECLAMATION & U.S. ARMY CORPS OF ENG'RS, Water Management Plan – 2026, app. 1, attach. 1 (2025). https://public.crohms.org/tmt/documents/wmp/2026/Appendix/Appendix_1_Emergency_Protocols_20251202.pdf

[34] McManus Decl. ¶¶ 20, 21; Stevenson Decl. ¶¶ 34, 35.

implement in-season management actions[35]—including adjustment to fish passage spill implementation—to avoid the larger system problems that might create the need for use of the Emergency Protocols. However, not only does the Prop. Order not clearly include the Emergency Protocols for the range of adjustments that may be needed, the Prop. Order also places operators of the system closer to a level of having to rely on emergency actions at a frequency or magnitude that is unprecedented and puts human health and safety at risk.

19. In addition, the reservoir restrictions in the Prop. Order also make implementing emergency actions less reliable.[36] Responding to reliability concerns by implementing emergency operations by reducing spill quickly and increasing generation will result in reservoir bouncing, as described in ¶ 11 of this Declaration, and will result in violating forebay and tailrace elevation requirements.[37] These changes in spill and generation are not simultaneous actions, creating short term changes in water outflow that impact the downstream reservoirs levels. The resulting fluctuations in downstream reservoirs would require further operational adjustments to keep projects within the minimum operating pool ("MOP") ranges described in the Prop. Order. These cascading operational adjustments would further degrade the certainty of water available for generation in future hours, likely necessitating further changes in operations to address system reliability. The MOP restrictions on all projects also limit the amount of generation available. This could lead to circumstances where the actions necessary to maintain system reliability require generation increases beyond what can be provided by ceasing all spill. This could lead to dramatic instability to the downstream project operations and the inability to

[35] Planned transmission maintenance activities are coordinated in advance through the Fish Passage Operations and Maintenance (FPOM) forum to minimize conflicts with Biological Opinion objectives. The emergency protocols include steps that are vetted through the Technical Management Team in advance of fish passage season. BONNEVILLE POWER ADMIN., BUREAU OF RECLAMATION & U.S. ARMY CORPS OF ENG'RS, Water Management Plan – 2026, app. 1, attach. 1 (2022), https://public.crohms.org/tmt/documents/wmp/2026/Appendix/Appendix_1_Emergency_Protocols_February_25_2022_with-ATTACHMENT-1.pdf. *See also* Marshall Decl.¶14.

[36] *See* Stevenson Decl. ¶¶ 27-31; McManus Decl. ¶¶18-19.

[37] *See* also Marshall Decl. ¶¶ 18-19.

meet transmission system reserve requirements.

20. It is imperative for planned operations to ensure that power and transmission reliability is accounted for and should never require emergency actions to be used routinely as a management tool, counter to Hesse's unsubstantiated statements.[38] Deviations from planned operations are *only* implemented as a last resort and are meant to be used as short term tools to resolve power and transmission system reliability issues. To be clear, Hesse does not possess the minimum qualifications to provide any expert opinion on best practices for operating the FCRPS to meet its multiple purposes; he did not conduct any modeling on loss of load probability; and he does not possess any direct experience working with transmission dispatchers and project operators to meet reliability needs during system disturbances.[39] This is evident by his assertion that using emergency actions to modify fish operations is appropriate when in fact, this reckless notion would risk operating the FCRPS in an unsafe, irresponsible manner. The flexibility to implement short-term adjustments to avoid situations where an emergency action is necessary is nevertheless a critical tool intended to be used sparingly. This flexibility provides Bonneville with the ability to respond quickly to disturbances on the power and transmission system and therefore helps reduce the risk of far more significant power and transmission system reliability problems.

B. Misrepresentation of Proposed Operations as "No Different" from Operations included in Previous Fish Operations Plans

21. The Plaintiffs assert the spill operations described in the Prop. Order are implementable starting Spring 2026.[40] The supporting motion memorandum and declaration filed by Hesse claims that since the operations have been implemented "to some degree in the

[38] Hesse Decl., ECF 2541 at ¶ 64; 2025 Deposition of Jay Hesse ("Hesse Dep.") 186:13-25; 187:1.
[39] Hesse Dep. 187: 5-11; 15-23 [the transcript incorrectly mentions "loss of flow probability" whereas the questions related to "loss of load probability"; 188: 1-4; 204:18-23.
[40] Oregon's 2025 Mot. for Prelim. Inj., ECF 2530; Prop. Order, 3, 7.

past" and at many projects, "no difference" exists between previous operations.[41] The Plaintiffs and supporting filings fail to state up front that the operations in the Prop. Order have not been implemented at the same time (i.e., MOP restrictions on the lower Snake and lower Columbia rivers with the levels of spill included in the Prop. Order). Despite the representations in both the 2025 Declaration of Edward Bowles ("Bowles Decl.") (ECF 2531; Table 1) and Hesse Decl. (ECF 2541; Tables 2-6), these operations have never been implemented together or in other words, these operations have never been conducted at the same time. The more accurate representation is some of the operations have occurred concurrently at some of the projects, but not at all projects in the same operating year. These misrepresentations by Bowles and Hesse give the impression of the availability of clear data on the effects of the operations in the Prop. Order and serve to minimize the likely adverse impacts on human health and safety, which I discuss below, and adverse impacts to certain Endangered Species Act ("ESA") listed species and non-listed species discussed by my colleagues.[42]

22. The crosswalk between the Prop. Order spill operations to historical operating plans provided in Hesse Decl. Table 2 (¶ 59) is illustrative of the ever-increasing spring spill levels for which the Plaintiffs advocate. The unprecedented spill levels have increasingly severe consequences to regional power as described in this declaration (e.g., ¶¶39-42) and transmission services (¶¶43-54), with no corresponding evidence that high spill would result in more returning adult salmon and steelhead.[43]

23. The spill operations outlined in the Prop. Order during the spring and summer months on the lower Columbia River would roll back and, in some cases, eliminate key operational flexibilities designed to ensure transmission reliability. For example, at John Day Dam, switching to 125% TDG Gas Cap spill (24 hours per day, seven days a week) as listed in the

[41] Hesse Decl., ECF 2541 ¶ 59.
[42] 2025 Declaration of Jim Faulkner ("Faulker Decl.") ¶¶ 32-38; 2025 Declaration of Steve Smith ("Smith Decl.") ¶ 33; 2025 Declaration of Erin Britton Kuttel ¶¶ 34, 54.
[43] Faulkner Decl.¶¶ 27-30.

Prop. Order removes one of the key tools Bonneville uses for holding reserves on the lower Columbia River—a necessary operating requirement to ensure reliable transmission and avoid load disruptions (e.g., blackouts).[44] This tool allowed more generation and increased reserve holding capacity during daytime hours between 2019-2025, spilling between 32% to 40% of in-river flows when demand and reserve carrying requirements for power are highest. Importantly, these modifications did not substantially change the proportion of fish encountering the powerhouse.[45]

24. Furthermore, the Prop. Order modifications to summer spill at Ice Harbor Dam from 30% spill to 45 kcfs will yield increased spill at this project. The increase in spill volumes under most conditions at Ice Harbor Dam to 45 kcfs will increase the risk to transmission reliability for local load service, particularly in the Tri-Cities area during peak summer loads. Ice Harbor Dam provides reliable load service to the Tri-Cities area and is discussed in detail in the Stevenson Decl. (¶ 32).

25. The Prop. Order will significantly reduce power generation (losses described below vary by time of year and up to 1,400 average megawatts ["aMW"]) and deplete reserve carrying capacity at all projects in the lower Snake and lower Columbia rivers leading to power and transmission reliability risks that will harm human health and safety.

C. Impacts to Power System Reliability from Implementation of the Prop. Order

26. The Prop. Order has direct implications for Bonneville's ability to supply firm power from the FCRPS used by customers to serve their load, and Bonneville's statutory obligation to operate the federal power and transmission system to maintain the reliability of the broader electric system.[46] To be clear, the reliability of the regional power system will be at substantially

[44] McManus Decl. ¶¶ 18-19; Stevenson Decl. ¶¶ 20-21.
[45] Harnish et al., *Factors Affecting Powerhouse Passage of Spring Migrant Smolts at Federally Operated Hydroelectric Dams of the Snake and Columbia Rivers*, 80 CAN. J. FISHERIES & AQUATIC SCI. 1949 (2023).
[46] Since 2008 Bonneville has been sending regional utilities an Emergency Protocol Summer Letter to describe procedures to accessing Federal power in times of emergencies on neighboring

increased risk if the Prop. Order is granted. My staff's analysis of these risks utilizes the regional power system reliability metric referred to as "Loss of Load Probability" ("LOLP"). LOLP is expressed as a percentage that reflects the probability that the regional power supply is inadequate to meet the region's expected demand for electricity in a year. Higher LOLPs reflect the increased likelihood that the power system would be unable to meet demand. If the power system cannot meet demand, then power shortages or blackouts occur.

27. The loss of electric service in an uncontrolled manner risks human health and safety and results in significant economic damage to the region and the nation.[47] In the electric industry, it is acknowledged that one-hundred percent electric reliability is infeasible; planners instead endeavor to limit the frequency and scope of such interruptions to a defined standard, such as no higher than five percent LOLP, which was the regional standard when the Final CRSO EIS was published in 2020. Five percent LOLP means that, in one of every 20 years, the region would expect to experience one or more power shortages (i.e., rolling blackouts, which are controlled interruptions of electrical service to avoid equipment damage, or uncontrolled blackouts where cascading loss of load occurs).

28. As illustrated in Section III. *Current State of the Power System and Resource Adequacy*, under certain system conditions, regional resources[48] are already scarce and may not

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systems. *See, e.g.*, Letter from Michelle Cathcart, V.P. Generation Asset Management, Bonneville, to Northwest Power Pool Participating Organizations (Mar. 10, 2025).

[47] Even the controlled shedding of load in rolling blackouts to avoid uncontrolled cascading load loss has risks to human health and safety and significant economic impact as evidenced in the events in California in August 2020. *See* Ivan Penn, *Poor Planning Left California Short of Electricity in a Heat Wave*, N.Y. TIMES (Aug. 20, 2020), https://www.nytimes.com/2020/08/20/business/energy-environment/california-blackout-electric-grid.html. *See also* CAL. INDEP. SYS. OPERATOR, FINAL ROOT CAUSE ANALYSIS MID-AUGUST 2020 EXTREME HEAT WAVE 19–37 (2021) [hereinafter CAISO, FINAL ROOT CAUSE ANALYSIS], www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

[48] The LOLP analysis was performed for the regional system, not just the FCRPS, because utilities in the Northwest including Bonneville routinely buy and sell power in a wholesale market. If the FCRPS generation decreases, Bonneville would purchase more power from the wholesale market to meet its obligations or sell less surplus (or a combination) to other utilities

be adequate to meet demand. Achieving a higher level of power system reliability (i.e., a lower LOLP) requires an increase of power to meet energy demands. If the Court were to order the federal agencies to implement the operations included in the Prop. Order, the increase in spill and forebay restrictions would increase the LOLP of the regional power system differently throughout the year, substantially increasing the risk during time periods of high demand such as summer heat waves. The annual LOLP metric assesses loss-of-load events any time during the year, but extreme events are most likely in summer and winter seasons.

29. Bonneville subject matter experts used the GENeration Evaluation SYStem ("GENESYS") model to determine LOLP and compare three different operational scenarios: 2020 CRSO EIS ROD Selected Alternative (implemented in 2021),[49] Draft 2026 FOP,[50] and Prop. Order. The GENESYS model relies on datasets containing information about the regional generation resources and the forecasted power demand[51] (or load) similar to current Northwest Power and Conservation Council ("Council") projections and assumptions regarding the availability of power from independent power producers and imports from outside the region.

30. The GENESYS model estimates LOLP, based on weather-related load uncertainty and uncertainties in generator electrical output due to outages or water availability uncertainty (for hydropower generation or required spill equates to less water available for generating electricity). The model determines how to run the generators (i.e., dispatch) at each project (including the federal and non-federal hydropower generating projects in the Columbia River Basin), and power imports to meet the expected load of the Pacific Northwest in situations where

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who are looking for power to serve their own load. Thus, a decrease in FCRPS generation without the context of the regional system does not give a complete picture of Bonneville's or regional power reliability impacts.

[49] *See* TECH. MGMT. TEAM, 2021 FISH PASSAGE PLAN ("FPP") and Appendix E, Fish Operations Plan ("FOP") for spill and reservoir operations implemented in 2021, available at https://public.crohms.org/tmt/documents/fpp/2021/.

[50] Feil Decl. Exhibit B.

[51] *Council Reviews Needs Assessment Results Based on Simulating Northwest Power System in 2031*, NW. POWER & CONSERVATION COUNCIL (Oct. 29, 2025), available at www.nwcouncil.org/news/2025/10/29/pacific-northwest-power-supply-2025-needs-assessment/.

the aggregate regional resources fail to meet the load (resulting in power shortages).

31. Table 1 presents the LOLP results for the three operational scenarios that were simulated for implementation in calendar year 2026: 2020 CRSO EIS ROD, Draft 2026 FOP, and the Prop. Order. The 2020 CRSO EIS ROD operations, using Pacific Northwest loads and resource forecasts from 2025, would result in a LOLP of 18 percent (Table 1). The Draft 2026 FOP would result in a lower LOLP of 15 percent. In contrast, the Prop. Order will reduce power generation and thus result in a higher LOLP: 27 percent. The Prop. Order will significantly impact reliability in critical months where the region is already at risk of having insufficient power to meet demand and maintain reliability, particularly in the summer and early fall.

Table 1: Comparison of LOLP Analysis of Operations in the 2020 CRSO EIS ROD the Draft 2026 FOP, and the Prop. Order.*

Spill Operations	LOLP (%)	Risk of Blackout(s) / Power Shortage(s) (Years)
2020 CRSO EIS ROD **	18	1 year in every 6 years
Draft 2026 FOP	15	1 year in every 7 years
Prop. Order	27	1 year in every 4 years

** The LOLP analysis modeling does not include the adverse impacts to reliability from limited reservoir storage capacity from the Prop. Order's minimum operating pool reservoir elevation ranges. The LOLP values are thus conservative for the Prop. Order meaning the LOLP value is likely higher.*
***During the CRSO EIS, the LOLP analysis of the Selected Alternative was measured at 6.4% against the Northwest Power and Conservation Council's standard of 5%. Bonneville reviewed revised resource adequacy studies in its analysis of the Prop. Order noting changes to regional loads and resources and updated the LOLP analysis for the Selected Alternative with this information for this declaration.*

1. Adverse Impacts to Summer Reliability and LOLP from the Proposed Spill Operations

32. In this section, I will discuss the adverse impacts to system reliability in the summer and LOLP from the Prop. Order. The proposed decrease in power generation because of the increase in water spilled during the summer months, especially the month of August, would cause the most impactful change in the increase of the LOLP. The month of August drives a significant increase in LOLP due to the increase of spill from the levels in the 2020 Final CRSO EIS after August 15, thereby decreasing the power supplied by the CRS during high summer cooling loads (e.g., demand for power for air conditioning in homes, hospitals, businesses, etc.).

While extreme heat conditions have been experienced as early as April,[52] late August is typically when extreme heat events occur in the Pacific Northwest (and across the entire West). Extreme heat events increase the need for more power generation to meet load. Thus, the increase in LOLP associated with the higher levels of spill in late August under the Prop. Order could result in periods of power shortages or load shedding during heat waves, thus risking an increase in heat-related illnesses and deaths.

33. An example of an extreme heat event occurred in August 2020 when operations transitioned to a lower level of spill, which improved Bonneville's ability to provide reliable power and transmission and adequate resources for supplying power to meet cooling loads, ensuring public safety. From August 14 through August 19, 2020, the western United States experienced an intense and prolonged heatwave.[53] The increased demand caused several Balancing Authorities to declare Energy Emergency Alerts ("EEA" or "EEAs").[54] An EEA is a condition in which a Balancing Authority has exhausted all other resources and cannot meet its demand obligations, with a level of EEA-3 signaling load shedding is imminent or occurring.[55] In total, there were 18 EEA events during the extreme heat event and six entities declared an EEA-3. Although demand peaked on August 18, the most severe reliability consequence of the heatwave (load shedding in California) occurred at the beginning of the heatwave on August 14 and 15. Had Bonneville not transitioned to lower spill volumes (while still maintaining surface passage routes for fish) and the associated increased generation on the lower Columbia and lower Snake rivers on August 15, more severe regional impacts would have occurred during the event. The Prop. Order removes the lower spill levels required to respond to August heat events, and

[52] Stevenson Decl. ¶ 32.
[53] *Id.* ¶ 28.
[54] *See generally* W. ELEC. COORDINATING COUNCIL, AUGUST 2020 HEATWAVE EVENT REPORT (2021), www.wecc.org/sites/default/files/documents/progress_report/2025/August%2020 20%20Heatwave%20Event%20Report.pdf; *NERC Report Outlines Potential Electricity Disruptions in the United States this Summer*; U.S. ENERGY INFO. ADMIN. TODAY IN ENERGY (June 30, 2021), www.eia.gov/todayinenergy/detail.php?id=48536.
[55] N. AM. ELEC. RELIABILITY CORP., EOP-011-4, EMERGENCY OPERATIONS (2025) (EEA increasing severity of inadequate generation supply as level increases).

thus, the impacts to human health and safety would be in stark contrast to what happened in August 2020.

2. Adverse Impacts to Power Reliability from the Prop. Order in Fall and Winter

34. Bonneville utilizes zero generation operations[56] at the lower Snake River dam and reservoir projects to shift power generation from periods of typically very low energy use to hours where energy use is highest. This operational flexibility allows operators to reduce generation during nighttime hours, which is an important tool for Bonneville to efficiently use the lower winter water flows by concentrating energy production in hours of greater need. This ensures the region has adequate and reliable power during times of peak energy demand for winter heating, thereby reducing risks to human health and safety. It also avoids purchasing additional energy (if it is available given demand and water availability) that would increase the cost of serving Bonneville's customers during the time of year when the Pacific Northwest typically experiences peak energy use.

35. For context, in years prior to implementing the operations analyzed in the 2020 CRSO EIS Selected Alternative, Bonneville utilized zero generation operations at the four lower Snake River dams from December through the end of February, when there were few, if any, actively migrating anadromous fish present.[57] In 2005, the Action Agencies adopted[58] and implemented a System Operational Request ("SOR") through the TMT that defined the term "few" in the biological trigger of reduced fish passage counts; the annual trigger is based on that year's abundance of steelhead in the lower Snake River.[59] This definition of "few" adjusted the

[56] Zero generation operations are when turbine flow stops on the Snake River, but flow occurs through the fish ladders and navigation locks.
[57] U.S. ARMY CORPS OF ENG'RS, WATER CONTROL MANUAL FOR LOWER GRANITE LOCK AND DAM (1987).
[58] TECH. MGMT. TEAM, DISPOSITION OF 2005 SORS, https://public.crohms.org/tmt/sor/2005/dispositions.html#22 (last visited Nov. 18, 2025).
[59] Memorandum from Russ Kiefer, Chairperson, Salmon Managers, to U.S. Army Corps of Eng'rs, Bureau of Reclamation & Bonneville Power Admin. (Dec. 6, 2005), available at http://public.crohms.org/tmt/sor/2005/2005-22.pdf.

start of the operation until the passage at Lower Granite Dam[60] decreased to the numbers identified by NMFS prior to December of each year. On average, this trigger delayed the start of the operation until mid-December. The Action Agencies operated under this trigger from adoption in 2005 until 2020 and returned to this same operation in 2021 to present.

36. The 2020 CRSO EIS Selected Alternative included an expanded period available for utilizing the zero generation operations at the lower Snake River projects to allow for increased power generation when demand was higher and few, if any, fish species are migrating. It was determined by NMFS in their 2020 CRS Biological Opinion that the historical long-term average use of approximately once every three to five days on average at each project would not negatively affect ESA-listed species in the CRS.[61]

37. As reported to the Regional Forum during TMT meetings, the use of zero generation operations in the fall of 2020 was consistent with the frequency analysis performed by NMFS in their analysis of the 2020 Proposed Action operations.[62] Bonneville presented an in-depth analysis of the 2020 use of the zero generation operations to the TMT including an assessment of diel passage which indicated that 2020 passage was consistent with previous years and that 95 to 98 percent of adult steelhead and fall Chinook salmon, respectively, entered the Lower Granite Dam fishways during daylight hours.[63]

38. Finally, the Final 2026 Water Management Plan (posted publicly on October 1, 2025)

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[60] Steelhead passage numbers are measured at Lower Granite Dam as that project is the only project on the lower Snake River where adult fish ladder counts are available in December.
[61] NAT'L MARINE FISHERIES SERV., ENDANGERED SPECIES ACT SECTION 7(A)(2) BIOLOGICAL OPINION AND MAGNUSON-STEVENS FISHERY CONSERVATION AND MANAGEMENT ACT ESSENTIAL FISH HABITAT RESPONSE FOR THE CONTINUED OPERATION AND MAINTENANCE OF THE COLUMBIA RIVER SYSTEM 944 (2020) [[ACE01056214] ("2020 NMFS CRS BiOp").
[62] TECH. MGMT. TEAM, Facilitator's Summary (Sept. 23, 2020) ("TMT Minutes"); TMT Minutes, ¶ 3 (Oct 21, 2020); TMT Minutes, ¶ 3d (Nov 18 2020); TMT Minutes, ¶ 3d (Dec. 16, 2020); TMT Minutes, ¶ 5d (Jan. 20, 2021); TMT Minutes, ¶ 5c (Feb. 17, 2021), available at https://public.crohms.org/tmt/agendas.
[63] *See* BONNEVILLE POWER ADMIN., LOWER SNAKE RIVER ZERO GENERATION OPERATIONS (2021), http://public.crohms.org/tmt/agendas/2021/0120_Early_Season_ LSN_Zgen_ Use_Summary_TMT_20210120.pptx.

states Bonneville intends to utilize the trigger that had been a part of operations from adoption in 2005 until 2020 and also implemented in 2021-2025 water years (i.e., no change to operations agreed to in TMT in 2005 and 2021) consistent with the limited impact to salmon and steelhead from the zero generation operation analyzed in the 2020 CRSO EIS Selected Alternative and the associated ESA consultation.[64]

39. In the Prop. Order, Plaintiffs request the Court to prohibit the implementation of zero generation operations at the lower Snake River dam and reservoir projects. The inability to implement these operations, in addition to the requested minimum surface spill flows included in the Prop. Order is significant, contrary to the assertions in the Bowles and Hesse declarations.[65] For comparison, the mean generation loss attributed to the requested 5 kcfs spill during zero generation periods in the Prop. Order on the four lower Snake River projects averages 300 aMW from December through February, which translates to approximately enough power for 220,000 homes. However, the amount of generation losses during the six highest demand hours of the day averages 520 aMW (ranges from 360 to 650 aMW losses), which translates to approximately enough to power 380,000 homes (which is more homes than in Seattle, WA). Thus, the Prop. Order would have severe impacts on Bonneville's ability to provide power during peak winter heating time periods, risking human health and safety.

3. Adverse Impacts to Reliability and LOLP from the MOP Operations in the Prop. Order

40. The GENESYS model does not capture the negative impacts of the limited reservoir storage capacity requested in the Prop. Order, including the lower Columbia River MOP

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[64] BONNEVILLE POWER ADMIN., U.S. BUREAU OF RECLAMATION & U.S. ARMY CORPS OF ENG'RS, 2026 FINAL WATER MANAGEMENT PLAN, § 6.10.2, (2025), https://public.crohms.org/tmt/documents/wmp/2026/September_30/20250930_2026_WMP_Final.pdf.

[65] *See* Bowles Decl. ¶ 108; Hesse Decl. ¶ 64. Note: the 2026 Water Management Plan was finalized September 30, 2025 and was reviewed by the region, including Oregon (comments received to the Corps on August 21, 2025) and the Nez Perce Tribe (comments received to the Corps August 25, 2025) prior to its finalization. Planned 2026 Zero generation operations are consistent with the operations identified in SOR 2005-22; TECH. MGMT. TEAM, DISPOSITION OF 2005 SORS, https://public.crohms.org/tmt/sor/2005/dispositions.html#22.

operations. The proposed MOP operations reduce the capability of the projects to increase and decrease generation in response to changes in demand and to hold needed reserves.[66] Thus, the MOP operations would likely reduce the ability of the system to respond to events like heat events and cold snaps and therefore are expected to increase LOLP beyond the numbers I provided for spill impacts. These risks are not merely theoretical as evidenced by the 2000/2001 energy crisis, August 2020 heat event, January 2024 cold snap, and other events across the Western Interconnection in the past several years.[67]

D. Adverse Impacts to Columbia River System Power Generation From Implementing the Prop. Order

41. The range of monthly effects to power generation (measured as average megawatts or "aMW") are illustrated in Figure 3. Figure 3 shows the month-by-month range of generation impacts estimated from the Prop. Order for fiscal year (FY) 2026 using 30 years of water records: 1989 to 2018 (blue dots). The operations described in the Prop. Order are compared to the 2020 CRSO EIS ROD operations as the baseline or denoted by zero and a black line, which represent operations implemented in 2021. The maximum average loss of generation is estimated at over 1,100 aMW in the month of May—that is a loss of 1,100 MW per hour on the FCRPS. This loss of generation does *not* include the reduction in energy due to spill commitments for ESA-listed migratory species as proposed by the Action Agencies in the 2020

[66] Stevenson Decl. ¶ 21; McManus Decl. ¶ 19.

[67] *See generally* David Krause, *Natural Gas Generators Headed to California for Summer Emergency Use*, NEWSDATA (Aug. 20, 2021), available at www.newsdata.com/california_energy_markets/regulation_status/natural-gas-generators-headed-to-california-for-summer-emergency-use/article_696f42aa-01ff-11ec-a5d2-4fc7d95749de.html; *California Tells Consumers to Prepare to Conserve Energy in Heatwave*, REUTERS (June 14, 2021), www.reuters.com/business/energy/power-prices-soar-heat-wave-affects-california-us-west-2021-06-14/; U. TEX. AUSTIN ENERGY INST., THE TIMELINE AND EVENTS OF THE FEBRUARY 2021 TEXAS ELECTRIC GRID BLACKOUTS (2021), https://energy.utexas.edu/sites/default/files/UTAustin%20%282021%29%20EventsFebruary2021TexasBlackout%2020210714.pdf; CAISO, FINAL ROOT CAUSE ANALYSIS, *supra* note 47. Rob Nikolewski, *Report: A Combination of Factors Caused California's Rolling Blackouts in August*, SAN DIEGO UNION-TRIBUNE (October 7, 2020), www.sandiegouniontribune.com/business/story/2020-10-07/report-a-combination-of-factors-led-to-californias-rolling-blackouts-in-august.

CRSO EIS ROD. These spill commitments typically equate to an additional loss of 800 to 1,000 aMW on the lower Snake River (starting in early April) and another reduction of 1,000 to 1,200 aMW on the lower Columbia River (starting in mid-April). As Figure 3 demonstrates, the range of generation losses are highest during the Prop. Order spring spill operations (April through June) and summer spill operations (August). The range of water conditions illustrate the effects of the Prop. Order will be greater during some conditions (e.g., late April could experience greater impacts of more than 1,500 aMW). The large loss of generation in the spring months is a concern for Bonneville and its customers as this study shows a large decrease in the ability of the FCRPS to reliably provide power to preference customers.[68] Moreover, the Prop. Order's significant negative impact on power generation could impact transmission reliability based on the generation losses shown in Figure 3, especially when reliability of transmission service is most at risk during lowest river flows in late winter (March) and summer (August) months.[69]

42. By comparison, Figure 3 also includes the Draft 2026 FOP operations (green dots) compared to the same 2020 CRSO EIS ROD baseline operations. There is increased generation in the period of April through June, resulting from a decrease in spill to the 120% TDG levels. This target spill was chosen for improved fish survival.[70] There is decreased generation in March because of increased surface spill for fish, which decreases the energy production for that month. Lastly, the Draft 2026 FOP includes a transition to late summer spill on August 1 (consistent with the operations implemented in 2024 and 2025), increasing the available generation during a period of high risk for transmission reliability events.

[68] *See* supra fn 2.
[69] *See, e.g.,* Stevenson Decl. ¶¶ 28-29.
[70] 2025 Declaration of Kelsey Shea Swieca ¶¶ 35-37.

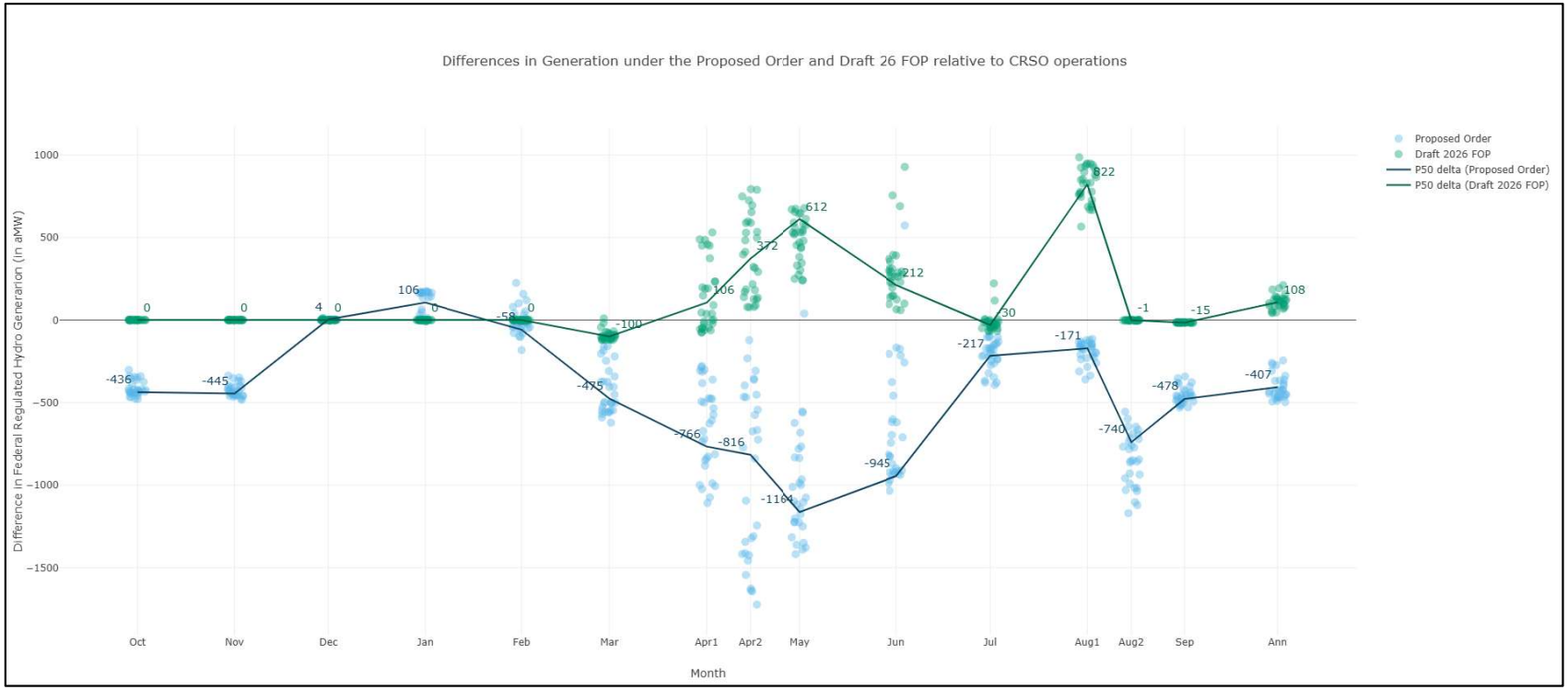


Figure 3: Monthly differences in hydropower generation (average megawatts or aMW) under the Proposed Order (blue dots) and the Draft 2026 Fish Operations Plan (green dots) relative to 2020 CRSO EIS ROD operations (denoted by 0 or baseline as a black line). Distribution represents differences under 30 historical water year conditions (1989-2018) from the modified flow dataset.

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E. Impacts to Transmission System Reliability from Implementation of the Prop. Order

1. The Prop. Order will Cause Increased Frequency of Operations at Minimum Generation Restricting Bonneville's Ability to Meet Requirements to Hold or Deploy Reserves

43. The spring spill operations included in the Prop. Order eliminate the up-to-eight-hours of performance standard level spill per day that was developed in the 2019-2021 Spill Operation Agreement[71] and included in the Selected Alternative in the 2020 CRSO EIS ROD. The Prop. Order also increases the John Day Dam spill to 125% TDG levels during the spring spill season and increases summer spill at the John Day and Ice Harbor dams. These increases are in addition to the increased spill amounts from recent levels at all projects from August 15 to August 31.

44. Minimum generation operations occur during low river flow conditions when there is insufficient flow in the river to achieve both the spill levels for fish passage *and* the minimum flow through the powerhouse, both of which would be specified in the annual FOP. When this occurs, flows through the powerhouse are limited to the specified minimum generation levels, and all remaining available water is prioritized for spill and other outlet structures, such as juvenile fish bypass systems. When a project is operating at minimum generation, all river flows in excess of flow for minimum generation at the powerhouse are spilled, and the amount of hydropower generation at that project is fixed, such that the project is unable to vary power generation levels up or down. As a result, minimum generation levels provide the minimum amount of generation necessary to provide voltage support and inertia for the reliable operation of the transmission system.[72] When operating at or near minimum generation levels, the system has very little room, if any, to respond to reliability concerns.[73]

45. To address this issue, the annual FOP includes pre-coordinated operations to deviate

[71] ECF 2298.
[72] Stevenson Decl. ¶ 19.
[73] *Id.* at ¶¶ 19-21.

from minimum generation to hold or deploy reserves so that Bonneville can meet its firm obligation to hold its balancing and contingency reserve requirements. The uses of these pre-coordinated operations are recorded in the monthly FOP implementation reports that are publicly available.[74] However, the Prop. Order MOP requirements significantly reduce the fundamental capability to hold system reserves on the lower Snake and lower Columbia rivers, reducing the availability of this pre-coordinated operation to hold or deploy reserves and impacting the reliability of the system.

46. As discussed in the McManus Declaration, the continued growth of Variable Energy Resources ("VERs") such as wind and solar in the Bonneville Balancing Authority Area ("BAA") is increasing demand for Balancing reserve capacity.[75] Sufficient balancing reserve capacity is required to maintain system reliability and to meet mandatory North American Electric Reliability Corporation ("NERC") Reliability Standards and Bonneville's Tariff obligations.[76] Balancing reserve capacity must be held to allow for both the increase ("*inc*") and decrease ("*dec*") in generation.[77] Bonneville forecasts a significant growth in installed solar capacity into 2028.[78] By spring 2026, installed solar capacity is expected to increase from 219 MW to 459 MW, all the way up to 2629 MW by September 2028.[79] Under current operations and the forecast of installed VER capacity, Bonneville is expecting to run out of balancing reserves beginning in February 2027.[80] However, Bonneville will be unable to meet reserve requirements starting as early as 2026, and will not have sufficient lead time to address the

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[74] *See* FOP Monthly Implementation Reports, https://public.crohms.org/tmt/documents/FOP_Implementation_Reports.
[75] McManus Decl., ¶ 9.
[76] *Id.* at ¶¶ 11-13.
[77] *Id.* at ¶¶ 6–7.
[78] *Id.* at ¶ 9.
[79] BONNEVILLE POWER ADMIN., BP-26-FS-BPA-06A, BP-26 RATE PROCEEDING, GENERATION INPUTS STUDY DOCUMENTATION, 5 tbl. 2.1, 13 tbl. 2.9 (2025), available at www.bpa.gov/-/media/Aep/rates-tariff/bp-26/Final-Proposal/Studies-and-Documentation/BP-26-FS-BPA-06A-Generation-Inputs-Study-Documentation.pdf
[80] McManus Decl. ¶ 14.

shortfall if the Court grants the Prop. Order.[81]

47. Under the spill levels analyzed in the 2020 CRSO EIS ROD, the fish passage projects were operated in the spring up to 125% TDG (16 hours per day) with eight hours per day of performance standard spill (i.e., lower spill levels), which helped limit the potential impacts of sustained operation at minimum generation levels. The change in spill operations requested in the Prop. Order would eliminate the eight hours of higher generation capacity that provides relief from the concerns of continuous minimum generation and result in an appreciable increase in the amount of time required to operate at minimum generation during spring and summer spill operations (see Figure 4, below). This is particularly true in low flow conditions, which can occur in all but the highest water years. In contrast, the Draft 2026 FOP operations would be similar to the 2020 CRSO EIS ROD operations, with some adjustments: 1) limiting spill to 120% TDG in order to decrease instances of gas bubble trauma[82] and reduce adverse impacts to juvenile and adult fish passage observed under higher spill levels and 2) decreasing spill in August when there are very few juvenile salmon actively migrating downstream through the CRS. Both operational adjustments would decrease the number of hours the system operates at minimum generation, thus providing increased transmission reliability and avoiding unacceptable risks to human health and safety.

48. To evaluate the effects of requested changes in spill operations, including an estimated quantification of increased frequency operating at minimum generation conditions during the spring season, my staff used the RiverWare model to simulate the daily and hourly operation of the FCRPS with a 30-year hydrological record spanning 1989–2018. Figure 4 shows the expected percentage of time the eight dams are predicted to operate at minimum generation when meeting the spill requirements for the operations in the 2020 CRSO EIS ROD,

[81] *Id.*
[82] 2025 Declaration of John Plumb ("Plumb Decl.") ¶¶ 20-22; *see also* Tiffan, K.F. and B.D. Liedtke, *Gas Bubble Trauma Progression and Mortality in Sculpin, Threespine Stickleback, and Northern Pikeminnow*. 98 NW SCIENCE (Nov. 4, 2025), at 174-189.

Draft 2026 FOP and Prop. Order. The Prop. Order significantly increases the frequency of time the dams must operate at minimum generation compared to the 2020 CRSO EIS ROD and Draft 2026 FOP. In the spring months, the Prop. Order requests spill increases of 125% TDG levels (gas cap spill 24 hours per day, seven days per week) at all dams except The Dalles and Little Goose dams. In the summer months, the difference in operations in July at Ice Harbor Dam is due to a change from 30% spill (from 2020 CRSO EIS ROD) to 45 kcfs (request in the Prop. Order); the increases of minimum generation in August are the result of spilling at elevated levels the entire month. The decrease in hours at minimum generation at The Dalles Dam and other dams in July results from a lack of ability to operate at minimum generation (when demand is low) and subsequently, dams are generating during peak periods due to the minimum operating pool limitations.

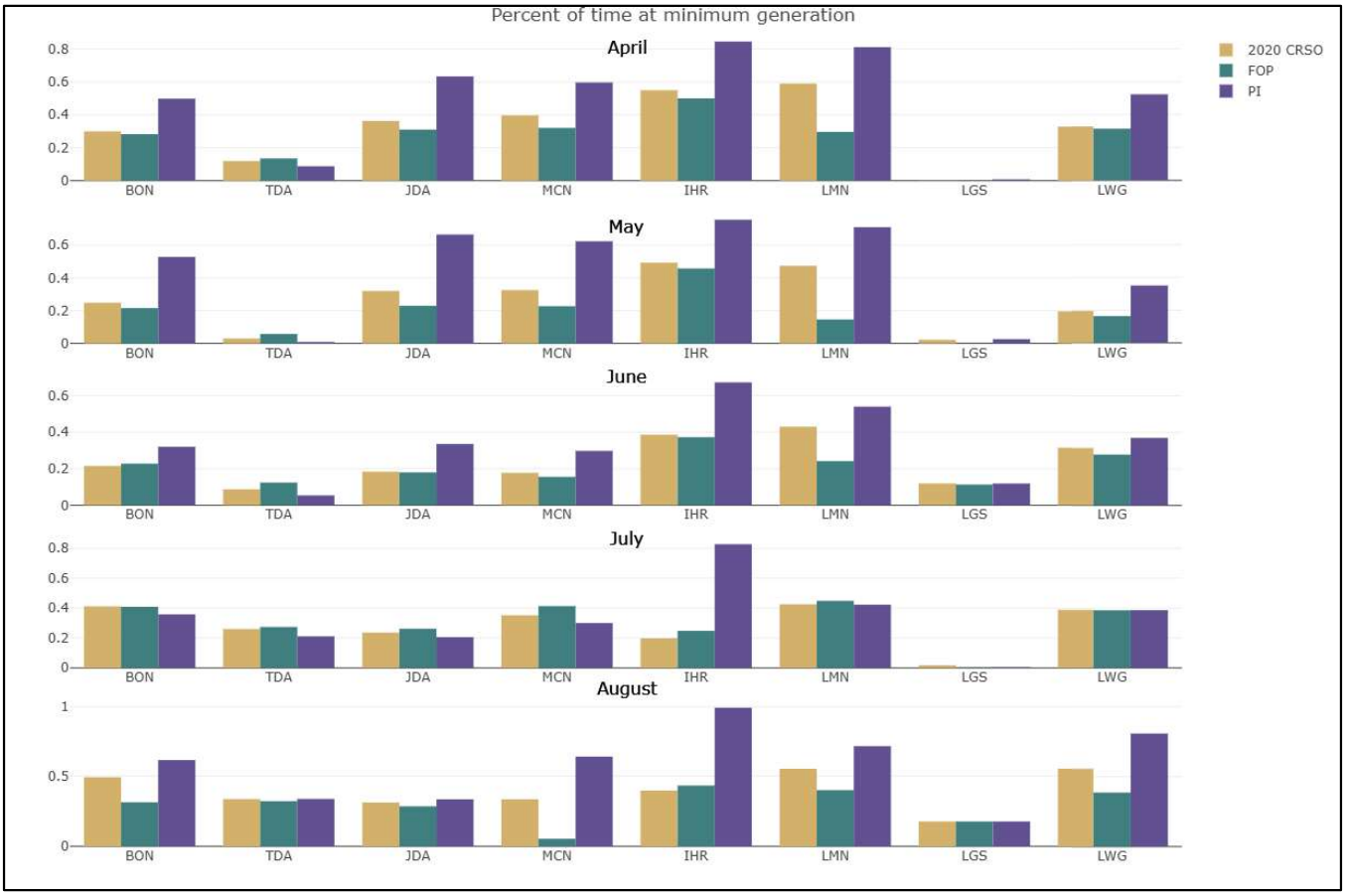


Figure 4: Percent of time each dam on the Columbia River System operates at minimum generation each month under the 2020 CRSO EIS ROD, Draft 2026 FOP and Proposed Order operations (denoted as "PI"). Minimum generation flow ranges are specified in the 2026 Draft Fish Operations Plan, Table 1.[83]

49. To put Figure 4 into context, the high prevalence of minimum generation occurrences with the Prop. Order raises urgent concerns. During 2020 CRSO EIS ROD operations (even under low flow conditions), the minimum generation conditions that occur in spring are ameliorated during the eight hours of performance spill when projects adjust power generation levels to provide reliability services during high demand hours.[84] However, under the Prop. Order, six of the eight projects face a significantly higher risk of being at minimum generation in the spring than under the 2020 CRSO EIS operations. The two exceptions are The Dalles Dam, requested to be maintained at 40% spill, and Little Goose Dam,[85] which typically begins

[83] *See* Feil Declaration, Ex. B.
[84] *See* Stevenson Decl.¶¶ 18–21.
[85] *See* Feil Decl. app. B, tbl. B-1 (Summary of spring spill operations implemented at four lower

performance standard spill during the day by late April, when high power generation demand hours overlap with known adult passage issues from high spill. The increased frequency of operating the projects on the lower Columbia and lower Snake rivers at minimum generation for some portion of those seasons in most water years will significantly reduce the transmission reliability support available from the lower Columbia and Snake River dams in certain low flow conditions.[86]

50. Moreover, when the Prop. Order spring spill operations are coupled with the requested MOP levels, the system is unable to use storage space to match fluctuations in energy demand. It is this loss of flexibility that increases the risk of a transmission system emergency and, ultimately, the risk of a blackout. The risk is especially acute in circumstances where the transmission system requires relief from a specific geographic location. As described in the Stevenson and McManus Declarations, projects on both the lower Columbia River and the lower Snake River are uniquely situated to provide the flexible generation to avert particular planning or operating shortages in particular circumstances.[87] These negative impacts from the loss of generation flexibility are *in addition to* the risk of power shortages from reduced generation (due to reduced water availability at individual projects) during high-demand periods.

51. Finally, as discussed above, the levels of summer spill in the Prop. Order increases the amount of time and number of projects required to operate at minimum generation during periods of hot temperatures and high summer demand, particularly in late August, when there are very few juvenile salmon actively migrating downstream through the CRS. With the lower river flows in August, the Prop. Order greatly increases the occurrence of minimum generation at these projects. This in turn decreases the number of FCRPS projects available to operate flexibly in times of highest energy demand, which reduces the ability to adjust generation in response to

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Snake River and four lower Columbia River dams since 2017, including the Plaintiffs' most recent proposed preliminary injunction operation).

[86] Stevenson Decl. ¶¶ 24–27.

[87] *Id.* ¶¶ 28-34; McManus Decl. ¶ 18.

the reliability needs of the transmission system. Combined with the reduced ability to carry reserves noted in paragraph 52 to 54, these operations could lead to unstable conditions that jeopardize both grid stability.

2. The Prop. Order will Severely Restrict Bonneville's Ability to Hold or Deploy Reserves on the Lower Columbia River

52. As discussed in paragraphs 45 and 46, the most significant operational impact for Bonneville would be the limited ability to rely on the lower Columbia River projects for reserves if the requested minimum operating reservoir elevations are imposed. Typically, Bonneville needs to carry approximately 1,400 MW of total system *inc* reserves[88] and up to 1,100 MW of system *dec* reserves per the rate case. Under the Draft 2026 FOP, the amount of reserves regularly held on the lower Columbia River projects ranges between 500 – 700 MW.[89]

53. The Prop. Order reduces the operating ranges for the lower Columbia reservoir elevations. Operating the lower Columbia reservoirs within the 1.5' range above minimum operating pool has significant impacts on Bonneville's reserve carrying capability. A significant portion of the reduced reservoir will be allocated to hydraulic management, with the major issues being: 1) managing the inflow variability from two river reaches at McNary Dam; 2) accommodating large forebay bounces at John Day Dam; 3) managing the limited pool at The Dalles Dam; and 4) keeping Bonneville Dam's tailwater within the current spring and summer tailwater constraints. This leaves little operational flexibility for carrying reserves. To ensure the forebays are operated within the restricted range, my staff's analysis is that these projects would need to be planned for operating in the middle of their forebay ranges. Since deploying reserves for transmission stability requires rapid changes in outflow, these events directly impact forebay fluctuations. As such, only 200 MW of capacity (collectively) would be available to support

[88] McManus Decl. ¶ 14; the actual amount of required system reserves is based on the amount of load and generation on the system.
[89] The amount of reserves held on the lower Columbia River can be even higher when there are capacity restrictions on Grand Coulee dam when large amounts of water are required to draft the project for flood risk management while meeting water quality standards.

transmission reserves between March 1 and August 31 under ideal conditions, but with large forebay bounces or other water flow constraints on these projects, the amount of capacity for reserves would be further reduced.

54. As discussed in the McManus Declaration, 100 MW of capacity is needed to be available on the lower Columbia River dam and reservoir projects just for responding to frequency deviations. Therefore, the reservoir limitations included in the Prop. Order would leave only about 100 MW (using the 200 MW total indicated in paragraph 53) for holding or deploying contingency or balancing reserves on the lower Columbia and Snake rivers.[90] Without the ability to carry sufficient reserves on the eight lower Columbia and lower Snake River dam and reservoir projects, Bonneville would need to rely on only two upriver projects in the CRS (Grand Coulee and Chief Joseph dams), and as discussed in the McManus Declaration, would severely hamper Bonneville's ability to both carry and deliver reserves to ensure transmission system reliability.[91]

3. Bonneville Cannot Rely on Emergency Operations to Maintain Transmission Reliability

55. As described in Section IV E. 1., initial assessments by my staff indicate the spring and summer spill operations in the Prop. Order would increase the likelihood of the projects operating at minimum generation levels during the spring and summer season, especially during low flow conditions. Bonneville's ability to make minor adjustments to support transmission reliability would be limited under these conditions because the dams cannot change power generation levels with minimum generation constraints. The flexibility to manage the transmission system reliably is necessary to minimize the risk of uncontrolled disturbances on the transmission system that could result in more severe interruptions in planned spill for fish

[90] Specifically, the ability to carry reserves on the lower Columbia and lower Snake rivers will be limited because of the minimum operating pool restrictions.
[91] McManus Decl. ¶ 16–18.

passage and create human health and safety concerns.[92] With only Grand Coulee and Chief Joseph dams available for reserves, there will likely be an increase in the number of power and transmission system emergencies declared to access generation at the lower Columbia and lower Snake projects. Having only two projects carrying reserves does not provide sufficient flexibility, enough redundancy or geographic diversity for the size of the balancing area managed by Bonneville. Grand Coulee and Chief Joseph dams also require regular system maintenance, which would sometimes leave only one project available for the reliability of the *entire* balancing area.[93] Declaring an emergency to access generation on the eight projects on the lower Columbia and lower Snake rivers will interrupt the fish passage operations in the Prop. Order more frequently and lead to instability in reservoir management.[94] Quick generation increases can only be implemented with stored water, which is very limited under the Plaintiffs' proposed minimum operating pool elevations for the lower Columbia River reservoirs. This would require changes to operations at the lower Snake River projects if large increases in generation are needed, which would cause interruptions in fish passage operations at the lower Snake River projects as well. This scenario is exacerbated during time frames of low flows through the river, such as August, when there is limited flexibly to move generation around the CRS for resolving transmission system emergencies.

56. As seen in 2016,[95] extreme temperatures can occur outside of July and August[96] meaning the requested changes to spring spill could be interrupted to address human health and safety reliability needs. Additionally, with less storage capacity available at the lower Columbia River projects to minimize inflow fluctuations during volatile, spring streamflows, there will be more extreme increases and decreases of flows through the lower Columbia River to stay within

[92] Stevenson Decl. ¶ 34.
[93] McManus Decl. ¶ 18.
[94] Turner Decl. ¶ 39.
[95] *See* Stevenson Decl. ¶ 32.
[96] Clifford Mass et al., *The Pacific Northwest Heat Wave of 25–30 June 2021: Synoptic/Mesoscale Conditions and Climate Perspective*, 39 WEATHER & FORECASTING 275 (2024).

non-power constraints. When flow fluctuations occur, the forebays of the lower Columbia River projects have to offset the changes. Without the forebay space, there is a risk of not having the generation available to meet load, cutting reserves needed for transmission reliability, or running outside of the other constraints that could impact navigation, recreation, irrigation, or fish operations.

57. Contrary to the Hesse Declaration,[97] Plaintiffs do not address the potential for impacts on system reliability from the requested minimum operating pool elevations in the Prop. Order. Rather they suggest the existing Emergency Protocols are sufficient to manage emerging reliability issues even though their Prop. Order eliminates the historic forebay ranges that underpin this set of procedures.[98] Managing the integrated federal power and transmission system responsibly necessitates understanding the impacts, including the most extreme risk scenarios, and planning accordingly to minimize risks to the operational reliability of the regional power grid, and ultimately, to human health and safety. Under Section 215 of the Federal Power Act, Bonneville is required to take those actions necessary to protect electrical reliability and human health and safety.[99] Under current operations, a transmission system emergency is a rare occurrence and declared only in response to unique situations. Under the Prop. Order, Bonneville does not have the same ability to respond to system conditions to avoid an emergency. Emergency operations are likely to be required more frequently rather than unique situations. Bonneville's transmission operators need generation flexibility to manage transmission constraints proactively to maintain grid reliability to avoid the need to declare transmission system emergencies.[100]

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[97] Hesse Decl., ECF 2541 ¶ 64.
[98] *Id*.
[99] 16 U.S.C. § 824o, Pub. L. No. 109-58, 119 Stat. 594 (2005).
[100] I am concerned that all of these factors in a Court order could have a chilling effect on the likelihood that Bonneville transmission dispatchers, working in coordination with Bonneville hydropower schedulers and the federal system operators, will take smaller management actions sooner, when the impact on fish operations might be brief and relatively inconsequential. Delaying short-term management actions may, in turn, increase the risk of a more serious

V. Operational Obstacles with Managing Reservoirs under the Prop. Order

A. Increased Violations of Tailwater Constraints at Bonneville Dam

58. Under the Prop. Order, managing the lower Columbia River within the 1.5' range above minimum operating pool would remove flexibility on the CRS to manage river flows.[101] An example of one constraint is the impact on the ability to meet tailwater change restrictions at Bonneville Dam. For human health and safety purposes, Bonneville Dam has a constraint for its tailwater rate of change.[102] The Marshall Declaration describes the purpose of this constraint and the water variability that the CRS must accommodate.[103] To analyze how frequently the Bonneville tailwater constraints may be violated, staff developed an hourly assessment utilizing actual historical streamflow data from 2016 to 2025 with the proposed reservoir ranges in the Prop. Order and compared them to the ranges in the 2020 CRSO EIS ROD. Since the ability to use storage space is situationally dependent on numerous factors, two representative ranges were analyzed for the Prop. Order. The "Low Estimate" limits the changes that would occur at the three other lower Columbia River reservoirs (McNary, John Day and The Dalles dams) in response to higher inflow volatility and reservoir bounce issues. This would result in less reservoir space available for managing the Bonneville Dam tailwater and significantly impacts the probability of violating the Bonneville Dam tailwater restrictions (*see* Table 3). The "High Estimate" actively manages the lower Columbia River reservoirs to minimize Bonneville Dam tailwater violations. This would reduce the ability to address the risk of increased streamflow volatility or reservoir bounces because there is nowhere else to absorb those fluctuations. The analysis showed that operating to the Prop. Order would result in frequent violations of the tailwater constraint below Bonneville Dam.

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transmission disturbance, which in turn increases the likelihood of triggering a much more significant interruption in fish operations.

[101] Marshall Decl. ¶ 24.

[102] *Id.* ¶ 43.

[103] *Id.*

Table 3: Lower Columbia River minimum operating pool operation and probability of violating Bonneville Dams' tailwater constraints.

Probability (Percent) of Violating Bonneville Dam Tailwater Constraints			
		Proposed Order	
Year	2020 CRSO EIS ROD	High Estimate	Low Estimate
2016	0.27	1.98	11.28
2017	0.27	0.89	3.32
2018	3.87	6.08	15.5
2019	0.55	0.55	0.87
2020	1.77	3.37	11.2
2021	2.29	4.22	20.35
2022	1.91	5.93	18.98
2023	1.23	3.63	16.94
2024	7.42	13.36	36.43
2025	1.08	9.92	30.91
Average	***2.07***	***4.99***	***16.58***

B. Adverse Impacts of the Prop. Order on Operations at the Upper Columbia Dams

59. The cumulative increase in spill volumes in the Prop. Order between March 1 and August 31 will have substantial operational effects on the federal dams in the upper Columbia River. The Prop. Order's spill levels at the lower Snake and lower Columbia river dams, especially during the spring and summer months, will result in a reduction in generation capacity of the FCRPS. The effects of the Prop. Order will require Bonneville to carry reserves for system reliability at the Chief Joseph and Grand Coulee dams. Specifically, my staff estimated that in 2026 approximately 450 to 500 aMW of reserves would need to be held at Grand Coulee and Chief Joesph dams. Holding reserves for Bonneville's BAA is not a luxury, it is a NERC requirement for safety and reliability of the Federal Columbia River Transmission System.[104] It is not always feasible to move all reserves to these two projects during times when the projects generation control systems must update, when there is necessary maintenance at these projects,

[104] McManus Decl. ¶¶ 11-12.

or when transmission requires greater diversity of reserves. Transferring reserves to Grand Coulee and Chief Joseph dams will result in less generation at both projects along with degraded value due to less generation capacity during peak hours of energy demand.[105] Additionally, this will cause forced spill at both projects to free up generation capacity needed for holding contingency and balancing reserves.

60. Regarding forced spill, during high flow conditions when Grand Coulee Dam is drafting for flood risk management or drum gate maintenance, generation that is decreased to hold reserves (contingency and *inc* balancing) will directly result in spill at Grand Coulee or Chief Joseph dams (or both). Spill can also occur under these water conditions when there are prolonged periods of *dec* balancing reserve deployments which decreases turbine flow. When Grand Coulee Dam is below the elevation where drum gates could be used for spilling water, spilling through the regulating outlets will increase TDG above the state and tribal water quality standards. Higher TDG levels can cause issues with net pen operations in the Chief Joseph Dam reservoir and managing TDG in downstream reservoirs. As discussed in the Plumb Declaration, increases in TDG levels can lead to resident fish mortality.[106]

VI. Financial Impacts of Implementing the Plaintiffs' Prop. Order

61. As noted above, Bonneville is self-financed, meaning it does not receive annual appropriations from Congress, and recovers its total costs through the sale of power and transmission services to regional utilities. The costs for providing these services are recovered through the power and transmission rates set by the Bonneville Administrator through a statutory process. The largest share of Bonneville's revenues comes from the sale of power to 134 regional public non-profit utilities ("preference customers").[107] These utilities make up 89% of

[105] *Id.* at ¶¶ 18-19.

[106] Plumb Decl., ¶¶ 19-20. *See also* Matthew G. Mesa, et al., *Progression and Severity of Gas Bubble Trauma in Juvenile Salmonids*, 129 TRANSACTIONS AM. FISHERIES SOC'Y 174–85 (2000); Don E. Weitkamp & Max Katz, *A Review of Dissolved Gas Supersaturation Literature*, 109 TRANSACTIONS AM. FISHERIES SOC'Y 659–702 (1980).

[107] *See supra* fn. 2.

Bonneville's total load, serving 27% of the region's consumers, reflecting 5.1 million households and businesses.

62. Power service to Bonneville's preference customers occurs under long-term power sales contracts, which are set to expire in 2028. These agreements require Bonneville to meet the firm power needs of its customers. For many of these customers, Bonneville is the sole supplier of the utility's power. These agreements ensure Bonneville has a long-term, steady stream of revenue to meet its various statutory obligations, including funding for its Fish and Wildlife Program. At the same time, these agreements also mean the level of Bonneville's power rates directly impacts the wholesale power rate costs of 134 public utilities that serve millions of regional consumers.

63. Bonneville's power rates are cost-based. These rates pass along to preference customers the total costs Bonneville incurs to maintain and operate the CRS and related non-federal generators, and to support a variety of regional programs. Critically, the amount of power generated by the CRS that Bonneville is able to sell directly impacts the level of the power rate for preference customers. Absent offsetting cost reductions, the less power the CRS generates, the higher Bonneville must set its power rates to recover its total costs.

64. In July 2025, Bonneville set its power rates for the period from October 1, 2025, to September 30, 2028 (referred to as "BP-26 power rates"). Due to increased cost pressures, Bonneville's BP-26 power rates increased by 8.9% compared to the previous rates. Also, on November 10, 2025, Bonneville announced that an additional 2% power rate increase was likely due to declining financial reserves.[108] Thus, Bonneville's customers are already facing a

[108] Bonneville holds financial reserves to manage risk and pay for unexpected costs that Bonneville may incur during a rate period after power rates are set. In 2017, Bonneville adopted a Financial Reserves Policy. *See* BONNEVILLE POWER ADMIN., BP-18-A-04, ADMINISTRATOR'S FINAL RECORD OF DECISION, app. A (2017), https://proceedings.bpa.gov/Home/OpenDoc?fileId=6081; *see also* BONNEVILLE POWER ADMIN., ADMINISTRATOR'S RECORD OF DECISION, FINANCIAL RESERVES POLICY IMPLEMENTATION (2018), www.bpa.gov/-/media/Aep/finance/financial-policies/rod-20180925-financial-reserves-

challenging year, with a prospective total power rate increase of 10.9%. Importantly, Bonneville set the BP-26 power rates assuming existing CRS operations (i.e., spill operations consistent with the Draft 2026 FOP). If the Court orders the Prop. Order, Bonneville's costs will increase even more due to the need to purchase additional energy to offset the reduction in the generating capability of the CRS. To evaluate the cost impact of the Prop. Order on Bonneville's customers, I asked my staff to calculate the relative rate impact if Bonneville set the BP-26 power rates with the Plaintiffs' proposed operations identified in the Prop. Order.

65. Relative to the BP-26 rate modeled operation, the difference in spring operations requested in the Prop. Order would change the shape of the energy output of the CRS and reduce its expected output, which is forecasted to be around 250 aMW for fiscal year 2026.[109] This value was calculated by my staff using current estimated spring and summer spill caps calculated by the Corps, and Bonneville's RiverWare model. This 250 aMW can power approximately 200,000 homes.

66. The 250 aMW reduction in energy generated by the CRS would affect Bonneville's power rates in two significant ways. First, the Prop. Order would reduce the capacity of the CRS, which Bonneville uses to provide a number of services that support reliable operations. Second, the Prop. Order would reduce the energy produced by the CRS. Both reductions impact Bonneville's costs and revenues by (1) increasing Bonneville's purchases of additional, non-federal energy and capacity on the open market in certain months, thereby increasing its costs; and (2) reducing the amount of surplus energy and capacity available for sale on the open market, thereby reducing Bonneville's revenues and increasing the costs that must be recovered from the power rates charged to preference customers.

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policy-phase-in-implementation.pdf. The Financial Reserves Policy and related policies established a minimum threshold for Bonneville's financial reserves. When financial reserves fall below that threshold, Bonneville's rates automatically adjust upward to replenish a portion of those reserves.

[109] The generation loss ranges from the 10th percentile (drier) 229 average megawatts to 90th percentile (wetter) 248 average megawatts for fiscal year 2026.

67. Bonneville staff used the Aurora model[110] to estimate the cost impact associated with the 250 aMW reduction in energy generated by the CRS over the 2026 fiscal year. My staff also modeled the impact to the Section 4(h)(10)(c) credits[111] and the loss of capacity revenues using the long-run marginal cost of capacity used to set BPA's rates. Collectively, the analysis showed that operating under the Prop. Order compared to the BP-26 rate modeled operations would result in an average of approximately $141 million in reduced revenues or increased power acquisition costs each year (or a combination of both), for a total of $424 million over the three-year rate period for fiscal years 2026, 2027 and 2028.[112] This cost estimate is based on an average of the 30 water years modeled, so actual costs will vary, but the Plaintiffs' requested operation would likely increase Bonneville's BP-26 power rates by an additional 6.4%.[113] This

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[110] Bonneville uses the Aurora model to forecast electricity prices. Aurora is a versatile production cost model widely used by utilities, regulators, system operators, and other planning entities to simulate the economics and operations of wholesale electricity grids. Aurora is a registered trademark of Energy Exemplar Proprietary Limited (ACN 120 461 716), the software developer. For further information about Bonneville's assumptions and implementation of Aurora, *see* BONNEVILLE POWER ADMIN., BP-26-E-BPA-04, POWER MARKET PRICE STUDY 3-24 (2025), www.bpa.gov/-/media/Aep/rates-tariff/bp-26/Final-Proposal/Studies-and-Documentation/BP-26-FS-BPA-04_Power-Market-Price-Study.pdf.

[111] The Northwest Power Act expressly authorized the Bonneville Administrator to make expenditures for fish and wildlife protection, mitigation, and enhancement from the Bonneville Fund, for both power and non-power purposes, on a reimbursement basis. *See* 16 U.S.C. § 839b(h)(10)(A) (2022). Section 4(h)(10)(C) of the Northwest Power Act ensures that the costs of mitigating these impacts are properly accounted for among the various purposes of the projects by making sure that when Bonneville funds mitigation on behalf of both power and non-power project purposes ratepayers can recoup the non-power share. 16 U.S.C. § 839b(h)(10)(C) (2022). Since the 1990s, Bonneville, Treasury, and the Office of Management and Budget agreed to a crediting mechanism against Bonneville's Treasury payments to reimburse Bonneville for expenditures made on behalf of mitigation for non-power purposes. Currently, Bonneville takes a 22.3 percent credit for expenditures associated with direct fish and wildlife programmatic spending, capital costs for habitat acquisition and construction activities, and replacement power purchase costs associated with lost firm hydropower generation due to fish mitigation measures.

[112] The BP-26 Rate case was based on HYDSIM modeling. In this declaration the BP-26 operational assumptions were updated using RiverWare modeling. These rate impacts are conservative because they do not include secondary cost and revenue implications.

[113] The $141 million was added as an expense for each year of the rate period in the BP-26 Rates Analysis Model (RAM) and rates were recomputed producing the 6.4% rate impact. The BP-26 RAM is publicly available at www.bpa.gov/energy-and-services/rate-and-tariff-proceedings/bp-26-rate-case.

increase would come on top of the 8.9% rate increase included in the BP-26 power rates and the 2% fiscal year 2026 rate increase that resulted from triggering the Financial Reserve Policy Surcharge to begin replenishing Bonneville's financial reserve levels. Together, this would be a 17.3% rate increase, which represents a rate increase in magnitude that Bonneville has not observed since 2002 when Bonneville had to increase its power rates 31.3% as the result of the California Energy Crisis. Imposing a rate increase of this magnitude on power rates would be extraordinary and would impose rate shock on end-use consumers. This rate shock would come at a time when end-use consumers are already experiencing elevated and unsustainable rises in costs—an unresolved issue that has raised questions of "affordability" at the utility level and more broadly cost of living concerns at the national level. Increasing Bonneville's power rates by nearly 20% would make these utility and national concerns worse.

68. To address the gap in the near term, Bonneville would have to reduce its program expenditures, draw down its financial reserves, or commence a new rate proceeding to raise rates (or some combination of the three). A $141 million loss per year to programs designed for public benefit would be consequential.

VII. Infrastructure Repair and Maintenance Injunction

A. Bonneville Funding summary

69. Now I will turn to the infrastructure repair and maintenance portion of the Prop. Order, including how the proposed projects are funded and prioritized as part of existing prioritization processes, and the constraints that impact the timeframe for project completion. As mentioned above, CRS projects are congressionally authorized for a variety of purposes that may include power generation, flood risk management, navigation, irrigation, water supply, recreation, and fish and wildlife conservation. Congress has mandated that costs tied to some of the purposes, notably power generation, are reimbursable. The beneficiaries of power generation, not taxpayers, are responsible for reimbursement of these costs. To determine the percentage of costs that each authorized purpose is allocated, an economic analysis, called the "Cost Allocation Report" is undertaken at each FCRPS dam when first constructed. This allocation is typically in place for the life of the project and is unique for each project.

70. Although there are a variety of ways a Cost Allocation Report can be performed, in all cases capital investment costs and operation and maintenance costs are broken down into two separate categories: "Specific" and "Joint." Specific costs are those that relate to only one authorized purpose and that purpose is assigned 100% of those costs. By contrast, Joint costs are those that benefit (or mitigate) more than one authorized purpose. For example, cranes needed to move equipment at the dam could be considered Joint because the crane is used to support more than one authorized purpose. Fish mitigation costs are also considered Joint because they are incurred to offset the operations of the dam as a whole rather than one particular purpose. Joint cost share is allocated to each authorized purpose under the Cost Allocation Report, and the percentages allocated to each purpose vary greatly between FCRPS projects given the combination of benefits provided by each project.

71. As the congressionally designated power marketer for FCRPS generation, Bonneville is responsible for all specific power costs and the "Power share" (i.e. the percentage allocated to

the Power purpose in the Cost Allocation Report) of Joint costs at FCRPS projects. Bonneville fulfills this responsibility by either reimbursing the Treasury for the power portion of appropriations given to the Corps, or it can directly fund the Corps.[114] In most cases, Bonneville directly funds these costs except when the Corps receives appropriations through the specific Columbia River Fish Mitigation ("CRFM") program appropriations.[115] In that case, the entire cost is funded through appropriations, and Bonneville repays the Treasury for the power share.

72. Bonneville cannot pay for costs that have been allocated to purposes other than power, absent explicit congressional directive. Instead, the Corps and Reclamation must obtain congressional appropriations to cover the non-power share of the total Joint costs. Because of this, even if Bonneville is prepared to directly fund its share of Joint costs, unless the Corps or Reclamation has received the matching congressional appropriations, the work cannot proceed.

B. Prioritization Process

73. As described in detail in the 2017 Declaration of Kieran Connolly ("Connolly Decl.", ECF 2145, ¶¶ 36, 43-46, 53, 56-58, 60, 63) , the 2017 Declaration of David Ponganis ("Ponganis Decl.", ECF 2142, at ¶¶ 10-12, 13-14, 16-22, 31, and 33 for Corps project implementation and funding process), and the Feil Decl. ¶ 51, 54, Bonneville, in coordination with the Corps and Reclamation, has a robust process in place through which the Action Agencies evaluate and prioritize investments at FCRPS projects. This process includes development of the "Strategic Asset Management Plan" and the "System Asset Plan," which identify and prioritize investment needs based on a number of different criteria. The System Asset Plan is evaluated and prioritized annually, and the Strategic Asset Management Plan is typically evaluated and prioritized every two years as part of Bonneville's rate setting process.

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[114] The Bonneville Project Act of 1937 and The Energy Policy Act of 1992 authorize Bonneville to directly fund the power costs allocated to FCRPS dams.

[115] Feil Decl. ¶ 54; Ponganis Decl. ¶¶ 10-12, 13-14, 16-22, 31, and 33 for Corps project implementation and funding process.

74. Also as described in the Connolly Decl., ECF 2145, ¶ 56, "[t]here are a number of factors the Agencies must evaluate in making investment decisions in the FCRPS, including economic, environmental, safety, and reliability, among others. Concurrently with the evaluation of these factors, the Agencies must also determine if there is available funding, power supply, planning capabilities, resources, and staff to perform the work, as well as the ability to meet non-power objectives—particularly environmental protection and safety."

75. For capital investments directly funded by Bonneville, there is an established project management process through which the Agencies analyze and decide the scope and timing of the investment. Representatives from the Agencies form the Joint Operating Committee, under which the Capital Work Group Subcommittee operates. The Capital Work Group, consisting of subject matter experts from each agency, collectively reviews numerous capital investment proposals and decides when each proposal moves forward. These decisions are informed in part by the Strategic Asset Management Plan and System Asset Plan, as well as budgetary information, unit outage schedules, and project management limitations. The Capital Work Group meets every other month; its review process is detailed in the FCRPS "Capital Investment Program Project Lifecycle Framework" as shown in Connolly Decl. ECF 2145 (Exhibit 1).

76. Once a capital investment is agreed upon, the Agencies execute a "subagreement" which explains the purpose, term, scope, and cost of the investment.[116] For most capital investments, several subagreement amendments are executed over multiple years with each

[116] Congress has entrusted, Bonneville, the Corps, and Reclamation to determine when power-related capital investments are necessary and appropriate at federal dams in the Pacific Northwest, including the fourteen multiple-purpose federal dam and reservoir projects that are at issue here. 16 U.S.C. § 832, 16 U.S.C. §839d-1. Bonneville is authorized to directly fund such capital investments, as well as any power-related maintenance activities, under this Direct Funding Authority. Pursuant to this authority, Bonneville has entered into four, separate direct funding agreements, two with the Corps and two with Reclamation. One set covers capital investments (Capital Memorandum of Agreement (MOA)) while the second set covers operation and maintenance. The Capital MOAs are "umbrella" agreements in that they cover the overall general guidelines the agencies follow, but for each specific capital project, a separate subagreement is executed.

amendment covering a different phase of work (e.g., design, construction, etc.) or changes in funding or schedule as more details become available.

77. Budget projections for investments in the CRS dam and reservoir projects are used in setting BPA's rates. Changes in the investment schedule, with one investment moving up in the priority list, would likely mean delaying or deferring other higher priority projects to avoid diverging from the projections used in setting rates and causing rate impacts to BPA's customers. As described in detail in the Connolly Decl. (ECF 2145, ¶ 82), this action could result in added labor and contract costs associated with extensions or termination, in addition to increased maintenance and reliability impacts.

C. Explanation of Infrastructure Repair and Maintenance Projects

78. I will now address the five *Infrastructure Repair and Maintenance* projects the Plaintiffs seek to accelerate completion of under the Prop. Order.[117]

a. The Dalles Dam Spillway

79. Planned work on The Dalles Dam Spillway gate 9 is included in a large capital project subagreement, approved on December 12, 2024, by Bonneville and the Corps for the rehabilitation of spillway gates 1-9. This Phase 1A subagreement is for the initial stages of work and provides funding from Bonneville to scope the work necessary to ensure the operability and reliability of the gates, including assessing the current condition of the gates; determining root causes of failure of equipment; evaluating options for repair; and determining cost and schedule to complete the recommended option. This scoping phase of the work was planned to be completed in FY25; however, the Deferred Resignation Program and government shutdown have impacted progress on this work, and now the expected completion is FY27.

80. Costs associated with the Spillway are considered Joint costs, and the Power share of

[117] *See also* Feil Decl. ¶¶ 48–51.

Joint costs under The Dalles Dam Cost Allocation report is 74%, meaning the Corps must obtain 26% of the funding from congressional appropriations prior to commencement of the work.

81. Under the 2025 System Asset Plan optimization process for work across the FCRPS, the Phase 1 design and Phase 2 construction are planned to occur between FY37-FY46.

82. The Prop. Order request for the repair of spillway gate 9 is related to but different than the agreed to strategy by Bonneville and the Corps.[118] Rather than a full rehabilitation which would identify the root cause of failures and provide a long-term fix, the Plaintiffs are requesting a temporary repair. If the Prop. Order is granted, this would have a number of adverse consequences, including diverting funds to the repair, which would delay other necessary work across the FCRPS given both project management and funding limitations. It would also negatively impact the long-term rehabilitation schedule and costs as resources would be diverted to the repair process. This is due to the increased scope caused by having to "undo" the short-term repair to instead proceed with the rehabilitation.[119]

83. As described above, Bonneville, Corps, and Reclamation have a robust system in place to determine when the ideal time to invest in a given project is within the larger context of managing the FCRPS. The Prop. Order's request would result in duplicative costs, direct impacts on the current investment strategy, and a potential delay in the rehabilitation that the Corps and Bonneville have identified as the best strategy for the long-term.

b. Bonneville Dam Stilling Basin Modification

84. Bonneville and the Corps have agreed and executed a subagreement on a project for rock mitigation of the stilling basin at Bonneville Dam, executed on October 11, 2022. This work includes constructing a barrier to prevent rocks from moving up the stilling basin and continuing to erode the spillway structure when operating spill volumes are above 150 kcfs.[120]

[118] *Id.* ¶ 55.
[119] *Id.*
[120] 2025 Declaration of Jon F. Renholds ¶ 31.

85. The cost of this project is Joint and the assignment under the Bonneville Dam Cost Allocation Report is 50% power and 50% funded through congressional appropriations. If funding is secured, the design phase will resume in FY26, with expected construction in FY28 (Oregon side) and FY29 (Washington side).

86. In addition to the required funding, there are also limitations on "in water work" requirements set by the states of Oregon and Washington at Bonneville Dam.[121] This limitation, in addition to needed appropriations, will prevent completion of this work within the "No later than February 28, 2027" timeframe identified in the Prop. Order.

c. John Day Dam Fish Ladder Temperatures

87. The Corps previously analyzed the availability of cooler water at John Day Dam, and the results are included in two water temperature reports.[122] These reports concluded that the availability of cooler water is limited; however, the Corps has continued to monitor water temperature, provide this monitoring information publicly, and investigate whether technical solutions are available to cool water consistent with the NMFS 2020 Columbia River System Biological Opinion Terms and Conditions.[123] The Corps' technical investigation work should

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[121] Feil Decl., ¶ 56 ("Due to short durations of Oregon and Washington in-water work windows designed to minimize impacts to ESA-listed fish species at the project that alternate between even and odd years on the two sides of the spillway (Oregon and Washington), a two-year construction phase is required.)

[122] *See* U.S. ARMY CORPS OF ENG'RS, LOWER COLUMBIA RIVER DAM FOREBAYS TEMPERATURE DEPTH PROFILE STUDY FOR 2018 (2019), https://public.crohms.org/tmt/documents/FPOM/2010/Temperature%20Reports/2018_Temp_Profile_Study_LCOR_Forebays_Final_Feb2019.pdf; U.S. ARMY CORPS OF ENG'RS, LOWER COLUMBIA RIVER DAM FOREBAYS TEMPERATURE DEPTH PROFILE STUDY FOR 2019 (2019), https://public.crohms.org/tmt/documents/FPOM/2010/Temperature%20Reports/2019_Temp_Profile_Study_LCOR_Forebays_Final_Nov2019_3.pdf.

[123] *See* 2020 NMFS BiOp, 1398 [ACE001057617] ("The Action Agencies shall monitor and report the temperature differentials in all CRS adult fishways. The Action Agencies shall monitor and report the forebay temperature profiles of mainstem lower Snake River and McNary dams. Other temperature monitoring may occur as needed to inform operations and/or designs. This program will be documented in the Water Quality Plan. Temperatures will be sampled on an hourly basis and this information shall be shared with resource agencies on a near real-time basis. . . . [The Action Agencies will also]. . . ii. Continue monitoring and reporting of all mainstem fish ladder temperatures and identify ladders with substantial temperature differentials

continue without interruption to allow the Agency subject matter experts the required resources, including time, to develop a functional, technical solution within the Corps' authority to implement.

88. This work is funded through CRFM appropriations, and the Corps would need to receive appropriations for the entire share. Bonneville would reimburse the Treasury for the power share of 77.5%.

d. Lower Granite Dam Auxiliary Water Supply Pumps

89. Bonneville and the Corps have executed a subagreement for addressing necessary work at the Lower Granite Dam Auxiliary Water Supply Pump. Under the Phase 1A analysis that was completed in October 2023, the preferred alternative covered motor rewinds, new bearings, new controls, and upgraded electrical. Currently, the design portion of the work has an expected completion date of May 2026. Construction is estimated to start in 2026 and be completed in 2030.

90. The costs associated with the auxiliary water supply pumps would be Joint costs and the cost assignment under the Lower Granite Dam Cost Allocation Report is 98.4% power. The Corps would need to receive congressional appropriations for the project in addition to Bonneville direct funding the power costs.

91. The agreed upon investment is related to but different than the request in the Prop. Order.[124] The current work will be completed on a faster timeline and will result in a more reliable water supply than current operations.

(>1.0°C). . . [and] . . .iv. Continue to investigate methods to reduce maximum temperatures and temperature differentials in adult fish ladders at mainstem lower Snake (other than Lower Granite and Little Goose Dams) and Columbia dams identified as having these problems and implement, if feasible.").

[124] Feil Decl. ¶ 58 ("The Plaintiffs' proposed action would change the scope from rehabilitation to pump replacement, which would delay the project schedule due to the need for redesign and the increased lead time to procure new motors.").

92. Lower Granite Dam has a total of three auxiliary water supply pumps. A major construction limitation that prevents completion of the work in the Prop. Order by February 28, 2027, is a project specific fish passage restriction outlined in the annual Fish Passage Plan. The Fish Passage Plan is a document reviewed, updated and coordinated annually within the Regional Forum Fish Passage Operations and Maintenance (FPOM) group and includes representatives from federal and state agencies and tribal nations. The Fish Passage Plan requires the pump facility to have a minimum of two functional pumps to maintain required flows during normal operations and most flow conditions; therefore, only one pump is allowed to be out of service at a time.[125] Based on this restriction, the Prop. Order's timeline is unrealistic and contradicts the Fish Passage Plan criteria that the regional fish managers have participated in developing, including representatives from the proponents of this action, including Oregon and amicus parties (i.e., Nez Perce Tribe and Yakama Nation).

e. Lower Monumental Dam Fish Transport

93. The transportation of juvenile salmon and steelhead at lower Snake River dams is part of the Proposed Action consulted upon in the 2020 NMFS CRS BiOp.[126] As referenced in the Feil Decl. (¶¶ 27 - 32) and Smith Decl. (¶ 46-47), transportation continues to provide benefits for ESA-listed species. In addition, fish transport continues to allow for critical species monitoring of in-river versus transported Smolt-to-Adult Returns. This monitoring is also a Term and Condition in the 2020 NMFS CRS Biological Opinion, and these transported fish serve as a vital comparison to fish experiencing in-river operations.[127]

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[125] *See* TECH. MGMT. TEAM, 2025 FISH PASSAGE PLAN, at ch. 9, § 2.4.2 (2025), https://public.crohms.org/tmt/documents/fpp/2025/final/FPP25_09_LWG_04-08-2025.pdf.
[126] 2020 BA at 2-54-2-55 [ACE001059565-66].
[127] *See* 2020 NMFS CRS BiOp, 1397 [ACE001057616] ("Monitor Smolt-to-Adult Returns of Transported and Inriver Migrating Fish i. The Corps and BPA shall continue ongoing transport survival studies for juvenile migrants passing Lower Granite, Little Goose, and Lower Monumental dams. Updated annual SAR estimates (and daily or weekly estimates if the data allow) for each transported species and their in-river counterparts shall be included in the annual progress reports or by other mutually agreed upon means. This will reduce take by providing the Action Agencies with information to further refine transport operations to optimize operations

VIII. Conclusion

94. It is possible to meet all authorized purposes of the CRS, including providing affordable and reliable power and transmission services, and meeting the federal agencies' statutory and regulatory requirements, in particular, complying with the Endangered Species Act. Bonneville is already engaged with its Action Agencies partners (Corps and Reclamation) in a deliberative, science-based assessment of potential operational improvements that resulted in the 2020 CRSO EIS Selected Alternative and Proposed Action (Chapter 2 from 2020 Biological Assessment) that was consulted upon under the ESA. These operations account for the complex interplay of ecological, economic, and human health and safety concerns associated with operating the CRS.

95. In direct contrast to this multi-objective approach, the Plaintiffs have requested injunctive relief which, if granted, will have severe and immediate consequences for the Bulk Power System in the Pacific Northwest. The Prop. Order would inflict significant harm to the operational safety and reliability of the CRS. Given the inevitable reliability failures and resulting public safety concerns the Prop. Order will precipitate and the limited time to evaluate and plan for consequences fully, it is simply a matter of which failure will occur, when, and how much catastrophic loss of human life and property will result.

96. If granted, the Prop. Order will force a greater than 17% rate pressure increase on Bonneville ratepayers, further exacerbating the affordability challenges many are facing. This would be in addition to the highest risk of a blackout and power shortage on record (greater than once every 4 years), resulting in an irresponsible level of risk to human health and safety.

97. The Prop. Order's summer spill operations in August risk power outages during extreme heat events when hospitals, businesses, and residences are relying on air conditioning to

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for Snake River spring and summer migrating fish to improve the survival of transported juveniles (or ESUs/DPSs as a whole).")

maintain safe temperatures. It also removes the ability to implement the zero generation operation at the lower Snake projects during December to February when few fish are migrating in the river, risking power outages during extreme cold events putting human health and safety at risk. Moreover, the minimum operating pool operations at the lower Columbia River projects would limit the Columbia River System's ability to respond to emergency energy events which can occur on short notice, increasing concerns to human health and safety from the Prop. Order.

98. Finally, the Prop. Order's combination of high spill levels and addition of minimum operating pool levels at the lower Columbia River projects, has never been implemented before and would result in more emergency declarations to decrease spill to carry and deploy the necessary levels of reserves. The Prop. Order also limits the ability of the Columbia River System's ability to respond to emergency situations due to lack of stored water resulting from the proposed minimum operating pool levels. The Prop. Order creates obstacles to meeting Columbia River System's multiple purposes that are in place for health and human safety.

I declare under penalty of perjury that the foregoing is true and correct. Executed on December 12, 2025.

RACHEL DIBBLE Digitally signed by RACHEL DIBBLE Date: 2025.12.12 11:52:27 -08'00'

RACHEL DIBBLE
V.P. Generation Asset Management
Bonneville Power Administration

EXHIBIT 116

IN THE UNITED STATES DISTRICT COURT

FOR THE DISTRICT OF OREGON

NATIONAL WILDLIFE FEDERATION, et al.,

Plaintiffs,

and

STATE OF OREGON, et al.,

Intervenor-Plaintiffs,

v.

NATIONAL MARINE FISHERIES SERVICE, et al.,

Defendants,

and

PUBLIC POWER COUNCIL, et al.,

Intervenor-Defendants.

Case No. 3:01-cv-640-SI

DECLARATION OF AUDREY STEVENSON IN SUPPORT OF FEDERAL DEFENDANTS' OPPOSITION TO PLAINTIFFS' MOTIONS FOR A PRELIMINARY INJUNCTION

I, Audrey Stevenson, declare as follows:

1. I received a Bachelor of Science degree in Renewable Energy Engineering from the Oregon Institute of Technology in 2012. My undergraduate studies included both electrical and mechanical engineering. I started working at Bonneville Power Administration ("Bonneville") in 2013 in the Transmission System Operations Division. I am currently a senior engineer with Bonneville's Transmission System Operations Division. I have been a member of multiple transmission operations-related task forces and teams, including: Western Electric Coordinating Council Path Task Force and RC West [1]System Operating Limits Methodology drafting team. My current duties include providing technical support and guidance to Transmission System Operations staff responsible for system studies setting operating limits for the transmission system; operating procedures for dispatchers; development of new processes for engineering staff; training for new engineers; and advising on emerging challenges affecting Transmission System Operations.

2. I have reviewed the motions for injunctive relief filed by the State of Oregon and the National Wildlife Federation-led Plaintiff group requesting a court order directing the U.S. Army Corps of Engineers ("Corps") to implement certain spill operations and minimum operating pool elevations, among other operations as detailed in Proposed Preliminary Injunction Order ("Prop. Order") (ECF 2530-2). In this declaration, I will address the following:

- The importance of voltage support and inertia to the reliable operation of the power system.
- The role that the generators at the lower Columbia River and lower Snake River dams play in providing this needed voltage support and inertia.

[1] *See infra* ¶ 5.

- The impacts of the Plaintiffs' proposed injunction on the reliable operation of the power system.

I. Introduction

3. Bonneville owns and operates approximately 15,000 circuit miles of high voltage (115 kilovolt – 1000 kilovolt) transmission lines used to deliver power to loads (energy demand) in Bonneville's service area, which includes Oregon, Washington, Idaho, western Montana and small portions of California, eastern Montana, Nevada, Utah and Wyoming. By statute, Bonneville is responsible for ensuring the electrical stability and reliability of the Federal transmission system in the Pacific Northwest.[2] Bonneville's transmission system also interconnects with major transmission systems delivering power between the Pacific Northwest and California, Canada, Idaho, Montana and Nevada. Bonneville's transmission system is an integral component of the interconnected electrical system in the western United States (Western Interconnection). Preserving reliability and stability is therefore critical not only for the Pacific Northwest region, but also for the entire Western Interconnection.

4. Maintaining the reliability and stability of the transmission system has evolved, initially through voluntary reliability standards (both internal Bonneville standards and standards developed by national and regional industry groups and entities). After the August 14, 2003 Northeast blackout that affected approximately 55 million people, Congress passed section 215 of the Federal Power Act.[3] Pursuant to that section, the Federal Energy Regulatory Commission ("FERC"), the Electric Reliability Organization (currently, the North American Electric Reliability Corporation ("NERC")), and the Regional Entity (currently, the Western Electricity

[2] Federal Columbia River Transmission System Act, § 4(d), 16 U.S.C. § 838b(d).
[3] 16 U.S.C. § 824o.

Coordinating Council for the Western Interconnection) have the jurisdiction to establish and enforce compliance with mandatory reliability standards approved by the FERC governing the operation of transmission systems and generation. As a Federal entity, Bonneville is not subject to monetary penalties for non-compliance but is subject to injunctive-type relief to enforce compliance.[4]

5. A core objective of the reliability standards is to prevent widespread power outages like the Northeast blackout event described below in Paragraph 10, thereby protecting public health and safety. Bonneville must comply with these reliability standards, which include requirements to ensure stability and voltage support on the system, and to provide generation reserves and automatic generation response to meet system needs.[5] The reliability standards also provide for a Reliability Coordinator (RC West is the Reliability Coordinator for Bonneville), which has a wide-area view of the interconnected transmission system, and has authority to direct transmission and generation operations to ensure reliability and stability.[6]

II. Overview of the Federal Columbia River Power System's Importance to the Reliability of the Power System

6. Maintaining stability is a critical part of ensuring the reliable operation of any power system (generation and transmission assets utilized to supply and transfer electric power). Understanding the underlying physics of power system stability is critical to understanding the impacts of the operations detailed in the Prop. Order on the reliability of the power system. The following is a brief overview of reliability concepts and how the Federal Columbia River Power

[4] *Southwestern Power Admin. v. Fed. Energy Reg. Comm'n.*, 763 F.3d 27, 33 (D.C. Cir. 2014).
[5] *See e.g.*, Reliability Standards BAL-001-2; BAL-002-3; BAL-003-2; TOP-001-6; PRC-006-5; and PRC-010-2, available at https://www.nerc.com/pa/Stand/Pages/USRelStand.aspx.
[6] Reliability Standards IRO-001-4; IRO-002-7; IRO-008-3; IRO-009-2; IRO-010-4, available at https://www.nerc.com/pa/Stand/Pages/USRelStand.aspx.

System ("FCRPS")[7], including the fourteen federal dams at issue in this litigation, supports the reliability of Bonneville's transmission system.

7. Certain electric generators, such as those at the lower Columbia River and lower Snake River dams, are comprised of large magnets (called the generator rotor) turning inside a large coil of wire (the generator stator). The rotation of the rotor inside the stator is what produces voltage based on a principle of physics known as Faraday's Law.[8] Electric power flows when a generator connects to a load via the transmission grid. These types of generators, when directly connected to the grid, are called "synchronous" generators. Variable resources, such as wind and solar generators, utilize different technologies and therefore, are non-synchronous generators.[9]

8. Voltage is required to push electricity from the power source through the transmission lines, and ultimately to the load. Synchronous generators play a critical role in the reliable operation of a power system, as they are able to maintain their voltage even during major disturbances on the power system. This is the concept of voltage support. Without adequate voltage support, the power system could not reliably transfer power to the loads, especially if the power has to be moved over a long distance. Voltage support is also vital to keeping the power system stable if a large short-circuit or loss of transmission facilities were to occur. Without

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[7] The FCRPS includes 31 multi-purpose dam and reservoir projects in the Pacific Northwest region, constructed and operated by the Corps and the Bureau of Reclamation, from which Bonneville markets and distributes power using the federal transmission system.

[8] David Halliday & Robert Resnick, FUNDAMENTALS OF PHYSICS (John Wiley and Sons. 2d ed.1981).

[9] Non-synchronous generators, such as wind and solar plants, can in some cases partially mimic the inertia and voltage support capabilities of a synchronous generator. However, this requires special equipment and control features that not all wind and solar plants have. Furthermore, the intermittent nature of these resources means that they are often not available when they would be needed to support the power system.

adequate voltage support, the risk of blackouts increases. Furthermore, voltage support has to be distributed throughout the system and cannot be concentrated in a few locations because the impedance of the power system causes the voltage to drop between locations with voltage support. If the locations with voltage support are far apart, the voltage between the locations declines to an unacceptable level and is ineffective at preventing voltage instability.

9. In addition, synchronous generators also provide significant rotating inertia. Inertia is the tendency of an object to resist changes in its state of motion. Inertia in the power system is created by the rotating mass of generators, which acts as a "brake" on the interconnected transmission system. When there is a disturbance on the transmission system (e.g., loss of a transmission line), the interconnected transmission system reacts to that disturbance. With more inertia on the transmission system, the system reaction to a disturbance is smaller or more stable. When a generator is running, it converts the energy in the fuel source into electrical energy (e.g., flowing water through a hydropower turbine). After a system disturbance, there may be a reduced ability to move the electrical energy across the system. Any energy that cannot flow across the system has the effect of speeding up the generator, which could cause significant damage to the generator. The more inertia on the system, the more energy it takes to change the speed of the generator, thus making the effect of a disturbance much smaller. This "braking" effect provided by the hydroelectric generators at the lower Columbia River and lower Snake River dams helps to minimize the rate of change of the speed of both these generators and generators throughout the Western Interconnection.

10. The 2003 Northeast blackout and several events in the Western Interconnection illustrate just how important voltage support and inertia are to power system reliability. The main cause of the 2003 Northeast blackout was inadequate voltage support following the loss of

several major transmission lines. In addition, the West Coast experienced a significant blackout on August 10, 1996, when a major 500kV transmission line in the Portland area tripped (unexpectedly went out of service), leading to the tripping of several other major transmission facilities and several generators at McNary Dam, which is one of the dams affected by the operations described in the Prop. Order. This disturbance resulted in the loss of power to 7.49 million customers, mainly in California, Arizona, and Nevada, during a time when many areas were experiencing 100-degree temperatures. The Western Systems Coordinating Council (the predecessor of Western Electricity Coordinating Council) issued a report on this disturbance in October of 1996, highlighting the importance of the need for adequate voltage support (also called reactive support in the industry) and inertia, as well as the critical role of the federal hydropower generators in providing these services. The following are two of the major conclusions contained in the report:

> 4. **Conclusion:** Immediately following the loss of the Ross-Lexington 230kV line and the Merwin – St. Johns 115kV line, the McNary units began tripping due to excitation system protection problems, withdrawing substantial real, reactive, and inertial support from the system. . . .
> . . . .
>
> 12. **Conclusion:** Special operations to protect fish (such as reducing generation and increasing spill at The Dalles) reduced the amount of real power, reactive power, and inertial support provided to the system, and therefore adversely impacted system reliability.[10]

11. Bonneville uses several metrics to assess if the power system is in a reliable operating state, including the voltage across the system. Bonneville, RC West, and other utilities throughout the Western Interconnection continually monitor voltages across the power system.

[10] *Western Systems Coordinating Council Disturbance Report for the Power System Outage that Occurred on the Western Interconnection August 10, 1996 1548 PAST,11-19* (Approved by the WSCC Operations Committee on October 18, 1996).

Low voltages are an indication of potential reliability problems, including potential instability and damage to customer equipment. In addition, these entities regularly run simulations to assess if unacceptably low voltages, overloads, or actual instability is likely to result if a major short-circuit or loss of transmission facilities were to occur.

12. Another metric used to assess the stability of the power system is the "phase angle." The phase angle is a measurement of how offset the voltage waveforms at two different locations in the system are from each other. The larger the phase angle, the more vulnerable the power system is to instability following a major disturbance. A large phase angle was a significant contributing factor to a major blackout in southern California on September 8, 2011.[11] This event occurred during a period of high heat and heavy loads in Southern California after the Hassayampa – North Gila 500kV line tripped, resulting in a phase angle of over 60 degrees between the Hassayampa and North Gila substations. This large phase angle prevented restoration of the line back into service in a timely manner. A series of overloads followed other transmission facilities serving load in San Diego and the surrounding area. Within 11 minutes, these overloads eventually caused cascading failures of the transmission system, leading to the tripping of the San Onofre Nuclear Generating Station and the loss of over 7,300 megawatts (MW) of load in southern California and Mexico, affecting more than 2.6 million customers in both countries.

13. The phase angle and associated instability risk can be reduced by decreasing loads or power transfers across the system, or by adding additional synchronous generators in between the two locations to increase the voltage support and inertia in that part of the system.

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[11] Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations*, (Apr. 2012), available at https://ferc.gov/sites/default/files/2020-07/Arizona-SouthernCaliforniaOutagesonSeptember8-2011.pdf.

Bonneville uses the phase angle between Grand Coulee Dam in north-central Washington and the Malin Substation on the Oregon-California border near Klamath Falls, Oregon as a key instability metric. Bonneville has performed operational studies that indicate, under normal conditions, a Coulee – Malin phase angle of 58 degrees or more means that the power system is vulnerable to instability. However, if the phase angle reaches 58 degrees, it may be too late to prevent the system from going unstable should a major short-circuit or line loss occur. These events are caused by such things as lightning, wind, icing, fires, and equipment failure, and happen on a regular basis. As a result, Bonneville must take action to reduce the phase angle far in advance of it reaching that level. In addition, major transmission facility outages occur frequently due to routine maintenance and emergency conditions such as inclement weather. These transmission outages can also reduce the acceptable Coulee-Malin phase angle limit (i.e., instability may occur below the 58-degree limit). The lower Columbia River and lower Snake River dams are in between Grand Coulee Dam and Malin Substation. Generation at these dams help decrease the phase angle which increases the stability of Bonneville's transmission system.

14. The lower Columbia River and lower Snake River dams also play a vital role in Bonneville's Remedial Action Schemes. Remedial Action Schemes are sets of automatic control circuits that switch various types of power system components on or off in response to disturbances on the interconnected transmission system. Remedial Action Schemes enable the transmission system to reliably transfer increased amounts of electric power by responding when certain contingencies occur on the system without having to build new transmission facilities.

15. A common type of Remedial Action Scheme is generator dropping (Gen Drop). In Gen Drop Remedial Action Schemes, one or more generating units are automatically tripped off-line when certain transmission equipment unexpectedly trips out of service. Although on-line

generation is generally needed for inertia and voltage support, there are some situations that require generation to be taken off-line in order to stabilize the system. Some of Bonneville's Gen Drop Remedial Action Schemes drop over 2,000 megawatts of generation under certain conditions. Generators at John Day, The Dalles, and McNary dams all play important roles in Bonneville's Gen Drop Remedial Action Schemes. These dams connect to the transmission system at locations where dropping a portion of their generation is an effective response to a number of power system disturbances.

16. Hydroelectric generators, such as the generators installed at the lower Columbia River and lower Snake River dams, are well-suited for use in Gen Drop Remedial Action Schemes due to their mass and slow rotational speed, which results in less likelihood of damage to the generators.[12] Other types of generators, such as gas turbines or steam turbines, rotate at much higher speeds and are therefore much more prone to damage if taken off-line suddenly by a Gen Drop Remedial Action Scheme. In addition, thermal plants take far longer (up to several hours in some cases) to be brought back on-line when they are dropped. Large hydroelectric generators can be put back on-line within minutes after being taken offline.

17. In addition to these broader system impacts, certain lower Columbia River and lower Snake River dams provide critical support to local load areas when transmission is unavailable or local demand is high. For example, Ice Harbor Dam provides support to the local load in the Tri-Cities area, particularly during outages of transmission facilities in the area. When one or more of the transmission facilities that enable power deliveries into the Tri-Cities area is

[12] The impacts of damage to a generator can be substantial. A considerable period of time is often needed to make repairs, there is a loss of inertia and voltage support to the power system, there is less generating resource available to meet customer load, and there is likely to be a considerable cost that must be borne by customers.

out of service or is overloaded, generation at Ice Harbor Dam is needed to support the load in the Tri-Cities area, relieve overloaded transmission facilities, and help maintain proper voltages in the area.[13] Part of this local load includes backup sources of station service[14] to the Columbia Generating Station nuclear plant.[15]

III. Impacts of Plaintiffs' Proposed Spill Operations and Minimum Operating Pool Elevations

18. I have considered the effects on Bonneville's transmission system of the spill operations in the spring, summer, and fall/winter and minimum operating pool elevations described in the Prop. Order. As detailed in the previous section, the lower Columbia River and lower Snake River dams are a vital source of voltage support and inertia, and Bonneville heavily relies on these dams to maintain the reliability of the power system. Each of the requested operations in the Prop. Order will reduce Bonneville's ability to utilize these dams to maintain reliable operation of the power system and will increase the potential for loss of load events (e.g. blackouts), which, in turn, poses increased risk to human health and safety.[16]

19. One outcome of the August 10, 1996, West Coast blackout was the establishment of minimum generation levels at the eight lower Columbia River and lower Snake River dams. Minimum generation levels set the minimum base level of generation needed to provide the voltage support and inertia required for reliable operation of the system. However, minimum generation levels assume normal operating conditions (all lines are in service), and do not

[13] *See* U.S. ARMY CORPS OF ENG'RS, 2025 Fish Operations Plan, App. E at 11, available at https://public.crohms.org/tmt/documents/fpp/2025/final/FPP25_AppE_04-08-2025.pdf.
[14] Station service is the power generated at that facility that is required to operate that facility's electrical components.
[15] As an illustration of the importance of station service, it was the loss of station service that led to the catastrophic meltdown at the Fukushima nuclear plant in Japan in March 2011.
[16] *See* Dibble Decl. ¶ 31 (showing Loss of Load Probability under the Prop. Order).

provide for generating flexibility to respond to system contingencies. As a result, Bonneville cannot reliably operate the system at minimum generation levels at all times, as the system is rarely in a state of normal operating conditions.

20. In 2021, Bonneville's Transmission Services group reevaluated these minimum generation levels. Transmission Services' analysis showed the need for an additional generating unit to be placed online at both John Day and The Dalles dams for voltage and inertia support under more stressed operating conditions, such as when there are both high loads in the Northwest and high power transfers to California from suppliers in the Northwest and Canada. Other adverse conditions, such as major transmission outages could further increase the required number of generators that need to be online.

21. In addition, analysis performed by Bonneville's Power Services group showed that the proposed spill operations and reservoir elevations in the Prop. Order would bring available generation at a number of the lower Columbia River and lower Snake River dams down to or very close to minimum generation levels for much of the year, depending on the type of water year.[17] As stated previously, operating at or near minimum generation levels leaves little to no room at the dams to respond to system contingencies. Thus, the proposed operation will increase risk to maintaining the reliability of the power system.

22. Bonneville's Transmission Services group evaluated these available generation values and conducted a preliminary assessment under new NERC Reliability Standard TPL-008-1, Transmission System Planning Performance Requirements for Extreme Temperature Events, which will be effective April 1, 2026.[18] Following tragic events in Texas during power outages

[17] *See* Dibble Decl. ¶ 48 and Figure 4.
[18] NERC, *TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events*, available at https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-

caused by storm Uri in 2021, the FERC took decisive actions to improve reliability of the bulk power system against threats of extreme weather that "may cause unacceptable risk to life and economic harm."[19] FERC issued Order No. 896 in June 2023 directing NERC and the electric power industry to develop a national reliability standard for Transmission System Planning performance requirements for extreme weather.[20] NERC conducted a fast-track development of the new Reliability Standard TPL-008 Transmission System Planning Performance Requirements for Extreme Temperature Events to address the FERC directive, resulting in Reliability Standards TPL-008-1.

23. Under TPL-008-1, Bonneville is required to complete an Extreme Temperature Assessment using extreme heat and cold benchmark events.[21] If the Extreme Temperature Assessment indicates that Bonneville's system is unable to meet certain performance requirements, Bonneville must develop a Corrective Action Plan to reduce the likelihood or mitigate the consequences and adverse impacts.[22]

24. Transmission Services' preliminary assessment for an extreme heat event under TPL-008-1 showed that the proposed spill operations and reservoir elevations in the Prop. Order will cause a 1,600 MW generation reduction at the lower Columbia River and lower Snake River dams.[23] The reduced generation will significantly increase the risk of load loss under extreme

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008-1.pdf. The study conducted by Bonneville's Transmission Services group was not conducted for compliance purposes, but only to get a preliminary picture of how the system would respond according to the Prop. Order. Bonneville will conduct a separate analysis according to the standard in line with the standard's timelines.

[19] Transmission System Planning Performance Requirements for Extreme Weather, 88 Fed.Reg. 41,262 (Jun. 23, 2023), available at https://www.federalregister.gov/documents/2023/06/23/2023-13286/transmission-system-planning-performance-requirements-for-extreme-weather.

[20] *Id.*

[21] *TPL-008-1* at R1 and R2.

[22] *Id.* at R9 and R10.

[23] The 1,600 MW value was derived from Transmission's TPL-008-1 study, comparing the

heat conditions, creating a significant risk to human health and safety. To resolve the potential loss of load, TPL-008-1 requires the creation of a Corrective Action Plan. A Corrective Action Plan could include the addition of dispatchable generating resources or building new transmission infrastructure to increase imports of generation resources from other regions. However, these solutions have years-long lead times, and there is no rapid solution that Bonneville could employ by the proposed timeframe of the Prop. Order. In the interim, Bonneville would be exposed to a significant risk of load loss (i.e., widespread power outages) during times when human health and safety are the most at risk in extreme heat conditions.

25. Transmission Services' analysis also showed that the Coulee – Malin phase angle could approach high risk levels with reduced generation at the lower Columbia River and lower Snake River dams under the spill operations and reservoir elevations in the Prop. Order. This is the case even under normal system conditions. This condition could be mitigated by putting more generation on-line in the same areas where the lower Columbia River and lower Snake River dams are located. While any generation, such as wind, solar, or gas, could help with the phase angle, these resources are not reliable sources of generation. Wind generation is intermittent and often produces at low levels during extreme temperature conditions when a reliable power system is vital. Solar resources are also intermittent and are, of course, unavailable at night. State greenhouse gas policies will likely limit the long-term availability of gas turbines in north-central Oregon and south-central Washington.[24] Gas turbines could also be subject to natural gas disruptions, as happened to a number of gas turbines in western

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generation dispatch under current operations to the generation dispatch that would occur under the Prop. Order for an August one hour extreme peak condition.

[24] These state greenhouse gas emission reduction policies disincentive fossil fuel generation by requiring emission reductions or placing a price on greenhouse gas emissions. In addition, Oregon's clean energy standard prohibits citing new fossil fuel generation in the state (OR. REV. STAT. § 469.413).

Washington and Oregon in March of 2019 when a gas pipeline fire in Canada limited deliveries. That leaves the power system dependent on reliable generation from the lower Columbia River and lower Snake River dams for the foreseeable future. If generation cannot be increased at the lower Columbia River and lower Snake River dams under the spill operations and reservoir elevations in the Prop. Order, then Bonneville would be required to either implement load curtailment (i.e. power outages) in the Northwest and/or reduce transfers to California (depending on conditions in California, this could lead to load curtailment in California) in order to bring the system back to a reliable operating state. These conditions would likely result in impacts to human health and safety because power would be unavailable to communities when it is needed.

26. The Coulee-Malin phase angle issue described above can also impact the deliverability of generation from the upper Columbia dams, the Puget Sound Area, and Canada. Operating the lower Columbia River and lower Snake River dams near or at minimum generation levels result not only in less generation available from those dams directly for service to load but may also prevent the delivery of electrical energy from additional key resources in the northern part of the system to load. This risk to overall system resource adequacy is expected to increase as other resources that can be relied upon for reliability, such as gas generation, are retired and more intermittent renewable generation is integrated into the transmission system.

27. Plaintiffs' proposed spill operations and reservoir levels will also have an adverse impact on Bonneville's Remedial Action Schemes, which utilize certain dams affected by the Prop. Order, such as John Day, The Dalles, and McNary. Under the spill operations and reservoir elevations in the Prop. Order, the amount of Gen Drop these dams could provide would be significantly reduced because the dams will already be at or close to minimum generation

levels. The less generation on line, the less Gen Drop will be available. If Bonneville could not carry the level of Gen Drop necessary at these dams, the only option would be to carry the Gen Drop at Grand Coulee and Chief Joseph dams and possibly at other non-federal generation sites. However, Grand Coulee and Chief Joseph dams already carry a considerable amount of Gen Drop, so there is little room for additional Gen Drop at these dams. Moreover, the proposed spill operations will result in Bonneville carrying nearly all of its required generation reserves at these same two dams.[25] This could result in a significant amount of generation being dropped from the transmission system at the same time that the same dams are needed to increase generation to supply reserves. Relying solely on the Grand Coulee and Chief Joseph dams to manage the reliability of the power system will significantly increase the risk of outages on the system. As stated previously, thermal generators are less effective and more prone to damage from the sudden dropping of generation and take much longer to come back on-line. Gen Drop has been installed at a number of renewable generation sites, but the intermittent nature of these resources means that they may not be generating and cannot be relied upon in all cases to supply the needed Gen Drop. Finally, performing Gen Drop actions at these alternative resources may not be as effective as Gen Drop at the lower Columbia River and lower Snake River dams because these resources' location on the transmission system may not provide an effective response to problems on a distant part of the transmission system. Thus, Gen Drop action may be less effective (thereby resulting in a reduced ability to transfer power across the power system), and it will take much longer to restore the power system to normal operating conditions if other resources are utilized for Gen Drop.

28. Several recent events illustrate how the operations in the Prop. Order will

[25] McManus Decl. ¶¶ 16-17.

adversely impact the operation of the power system. From August 14 – 16, 2020, the entire West Coast experienced a heat wave, resulting in high Northwest loads and transfers to California. At this time, there was 300 - 500 MW of generation on the lower Snake River dams and over 2000 MW on the lower Columbia River dams.[26] The Coulee-Malin phase angle topped 50 degrees, getting close to the point where Bonneville would need to take action to reduce the phase angle. A transmission restriction in the Northwest during this period resulted in limitations on the transfer of power to California. As a result, California had to drop 1,000 MW of load (roughly equivalent to the load in the city limits of Seattle) for an hour on August 14 and another 470 MW of load for 20 minutes on August 15.

29. I ran a simulation of this event with the lower Columbia River and lower Snake River dams adjusted based on operations in the Prop. Order. This shifted over 500 MW of generation to Grand Coulee Dam, Chief Joseph Dam, and resources in Canada. The simulation indicated that the Coulee – Malin phase angle would increase by nearly 1.5 degrees due to this shift in generation, a definite increase in system stress putting the system much closer to its 58-degree stability limit and likely requiring Bonneville to take actions to reduce the phase angle. As previously noted, California had to drop load during the actual event. Had the Prop. Order and the associated generation patterns been in place at the time, there is a strong possibility that California would be required to drop more load for a longer duration.

30. Another event I would like to mention is the Northwest heat wave that occurred from June 26 – 28, 2021. Temperatures and load levels in the Northwest reached unprecedented levels during this event. Fortunately, California was not experiencing a similar heat wave at the

[26] Under the Selected Alternative in the 2020 Columbia River System Operations Environmental Impact Statement Record of Decision, spill levels were reduced and generating capacity was increased in late August. Without the increased spill operations, generating levels would have been lower and the phase angle would likely have been higher.

same time, so transfers to California were not as high as they would have been. The Coulee – Malin phase angle ranged from 20° to 40°. Generation at the lower Snake River dams was over 900 MW and up to 3,000 MW at the lower Columbia River dams, contributing significantly to maintaining reliability during this time.

31. A simulation of the generation patterns that could be expected from the Prop. Order during this event required a reduction of over 1,400 MW at the lower Columbia River and lower Snake River dams, which was made up by increasing generation at the Grand Coulee and Chief Joseph dams and resources in Canada. This generation shift resulted in an increase in the Coulee – Malin phase angle of nearly 4 degrees. While this would not have put the system up to the stability limit, it still indicates that this generation shift added a considerable degree of stress to the system. Had California experienced a similar heat wave, the consequences would have been much more severe because increasing transfers to California would cause increased stress on the system, causing additional increase to the Coulee – Malin phase angle.

32. Finally, I would like to provide an example that illustrates how certain generating dams are critical for reliable service to a specific local load area. One of the best examples on Bonneville's system is the role that Ice Harbor Dam plays in providing reliable load service to the Tri-Cities area. This was very clearly illustrated by an event on April 19, 2016. On that day, the Tri-Cities experienced unseasonably high temperatures over 100 degrees combined with scheduled equipment outages that resulted in increased customer load and associated line loadings on the transmission system in the area.[27] Even with Ice Harbor Dam generating at 380

[27] For the Tri-Cities area and these outage conditions, Bonneville study engineers analyze the system two weeks in advance. In this case, Bonneville assumed spring heavy load hour conditions. This included Ice Harbor Dam generation at 365 MW and ambient temperatures ranging from 68° to 86° F. These studies did not include the extreme temperature conditions or shift to nighttime spill that actually occurred. If these factors were known in advance by the study engineers, it is possible some planned maintenance could have been deferred to allow more

MW, which is the approximate amount of electrical energy that can be generated when this dam is spilling at 45 thousand cubic feet per second for fish passage during daytime hours (6 AM to 6 PM) under the 2017 FOP in effect at that time, load service to the area was at risk because at least one transmission facility reached its allowable operating limit. Conditions became much worse when Ice Harbor Dam operators switched to gas cap spill levels as part of nighttime (6 PM to 6 AM) operations for fish passage in effect at that time, which caused generation to decrease to 68 MW. Due to the unavailability of transmission into the area and continuing heavy load conditions, generation could not be imported from other resources.[28]

33. Without additional generation, the Bonneville Transmission Dispatcher was faced with either implementing a controlled blackout of the local area, or risk overloads which could have resulted in equipment failure and uncontrolled blackouts. Uncontrolled blackouts and equipment failure have the potential for more severe impacts to human health and safety, as well as reduce the ability to implement fish passage spill operations, especially with the high temperatures at the time. Faced with no other options to ensure load service to the Tri-Cities

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imports of generation into the area. However, maintenance is crucial to ensure transmission equipment continues to function as intended and in a safe manner. Deferral of maintenance simply pushes out the effects into other time periods, when power demand may also be high. In addition, deferring maintenance increases the risk of equipment failure.

[28] This incident also highlights that it is critical for Bonneville, as the authority charged with maintaining the transmission grid within its jurisdictional territory, to rely on power generation from the federal projects, in particular, to maintain reliable electricity service to protect human health and safety. At the time of the event, the wind was not blowing, so local wind generation in the Tri-Cities area was not adequate to supply local power demand, since wind generators can only supply electrical power when wind spins the turbines. In fact, the total amount of power being generated by wind turbines connected to Bonneville's system at the time of this event was only about 150 MW (if operating at full capacity, wind generators connected to Bonneville's transmission system at the time could have generated 4,795 megawatts of electrical power, but only when the wind is blowing). Rooftop solar would not have helped even if it had been installed in this case, since the heavy power demand conditions lasted well past sundown. In short, the wind and solar resources in the area cannot be counted on to be available, let alone in the amounts needed, when events such as those that occurred on April 19, 2016, are encountered.

area, the Bonneville Transmission Dispatcher was forced to declare a transmission system emergency and directed Ice Harbor Dam generation to increase to 400 MW to avoid shedding load and causing local blackouts. As this situation demonstrates, the availability of generation at Ice Harbor Dam is critical to the local Tri-Cities area for load service in emergency situations, including, as previously noted, ensuring reliable backup station service to the Columbia Generating Station nuclear plant.

34. Plaintiffs' Prop. Order would reduce the generation at Ice Harbor Dam during the spring and summer months when it is needed to mitigate these types of high load conditions. In addition, Plaintiffs' Prop. Order could limit Bonneville's ability to increase generation at Ice Harbor Dam in response to unforeseen transmission outages or higher than expected loads in the Tri-Cities, even if Bonneville declared a transmission system emergency. If that is the case, then Bonneville may have to resort to shedding customer load in the Tri-Cities in order to maintain the reliability of the grid in the area. However, any customer load shedding (blackouts) carries with it a risk to human health and safety and failed implementation of fish passage operations.

IV. Conclusion

35. The requested changes in operations described in the Prop. Order at the lower Columbia River and lower Snake River dams would increase the frequency with which these dams operate at minimum generation levels, especially during low water conditions. [29] This, in turn, would increase the stress on the transmission system, particularly during periods of high loading and high transfers. This increased system stress would then make it more likely that service to loads in the Northwest would have to be interrupted or transfers to California would have to be reduced (which, in turn, could lead to interruption of California load) in order to

[29] *See supra* fn. 17.

maintain system reliability. In addition, other changes in the regional generation mix will make dependable generation from the FCRPS even more important. In short, the Prop. Order would likely push the transmission system to the brink of an emergency during times of high loading when the transmission system is already stressed; a state that the system should rarely be in. Pushing the transmission system to the edge increases the risk of major blackouts and could cause widespread risk to human health and safety.

36. Over the past several years, Bonneville has seen an increase in heatwaves, fires, and storms throughout the West. The increase in the number of these events has contributed to increased loads and a greater likelihood of equipment outages on the transmission system. If the generating capability of the lower Columbia River and lower Snake River dams is reduced to the extent proposed by Plaintiffs, the risk of major outages during times when power is necessary for human health and safety is increased significantly.

I declare under penalty of perjury that the foregoing is true and correct. Executed on December 11, 2025.

AUDREY STEVENSON Digitally signed by AUDREY STEVENSON
Date: 2025.12.11 14:25:53 -08'00'

AUDREY STEVENSON
Electrical Engineer
Bonneville Power Administration

EXHIBIT 117

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UNITED STATES DISTRICT COURT

DISTRICT OF OREGON

NATIONAL WILDLIFE FEDERATION, et al.

Plaintiffs,

and

STATE OF OREGON, et al.,

Intervenor-Plaintiffs,

v.

NATIONAL MARINE FISHERIES SERVICE, et al.,

Defendants,

and

PUBLIC POWER COUNCIL, et al.,

Intervenor-Defendants.

Civ. No. 3:01-cv-00640-SI

DECLARATION OF NANCY HIRSH IN SUPPORT OF PLAINTIFFS' REPLY IN SUPPORT OF MOTION FOR PRELIMINARY INJUNCTION

I, NANCY HIRSH, state and declare as follows:

1. I was employed at the NW Energy Coalition (NWEC) from April 1996 through August 2025. For the first eighteen years I was the policy director and then in 2015, I became the NWEC executive director.

2. I have a Bachelor of Science in Natural Resource Policy from the University of Michigan's School of Natural Resources and the Environment.

3. During my tenure at NWEC, I have developed substantial expertise from analyzing utility and regional resource planning and engaging in regulatory proceedings, utility rate cases, and utility program reviews. I worked with state policymakers and state agency staff on energy policy, clean energy development, state energy strategy, and greenhouse gas emissions and air pollution reduction approaches. I have prepared detailed comments for submission to state agencies, policymakers, and regulators in Oregon, Washington, and Idaho on utility industry restructuring, resource planning, and clean energy development.

4. Between 1999 and 2011, I submitted multiple rounds of testimony to the Washington Utilities and Transportation Commission and the Idaho Public Utilities Commission as part of utility rate case proceedings for Puget Sound Energy, Avista Utilities, and Idaho Power. I also submitted testimony and substantive comments during utility resource planning, energy efficiency and utility merger dockets.

5. I have been invited to provide testimony before Congress on two occasions. First in 1997 before the House Committee on Resources, Subcommittee on Water and Power. The hearing was on the Status of the Regional Review Process for the Bonneville Power Administration (BPA). In 2001 I testified before the Senate Finance Committee regarding BPA's role in Infrastructure development, energy efficiency, and load management.

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6. In 2001, I assisted NWEC staff in the preparation of testimony in a BPA rate case (WP-02 Phase II). During my career I have prepared and submitted numerous comments to the NW Power and Conservation Council (NPCC) on the Comprehensive Regional Review, the Future Role of BPA in Power Supply, the Regional Dialogue proposal, and carbon emissions, among others. Through this work, I have developed a reasonably detailed understanding of the role BPA plays in energy marketing and transmission in providing electricity to the people of the Northwest and the role of the federal dams on the Columbia and Snake Rivers.

7. In 2008, I was asked by Idaho Governor Otter to serve on the Idaho Strategic Energy Alliance. Since 2019, I have served on the Advancement Board of the Institute for Energy Studies at Western Washington University. In 2020, I was asked by Washington Governor Inslee to co-chair the advisory committee helping to develop the 2021 State Energy Strategy.

8. I reviewed declarations submitted by BPA staff – Rachel Dibble, Bartholemew McManus, and Audrey Stevenson.

9. In this declaration I will discuss my review of recent NPCC and the Pacific Northwest National Lab's analysis on the following topics: A) Resource adequacy of the power system under fish operations; B) Fish operations impact on energy and peak needs; C) BPA has Many Tools to Provide Flexibility, Balancing and Operational Reserves; D) Lower Snake River & Lower Columbia projects contribution to system balancing; E) Power system support for the Tri-Cities; F) Handling extreme weather events; G) Maintaining affordability.

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A. The Most Recent NPCC Power Supply Adequacy Assessment Shows that the Fish Operations, Including Those Similar to the Operations NWF Seeks in its Preliminary Injunction, Do Not Have a Substantial Impact on Resource Adequacy.

10. The NPCCis an interstate compact agency established by Congress in the 1980 Northwest Power Act.[1] The four state (Washington, Oregon, Idaho, Montana) agency is tasked with regional power system planning, establishing resource priorities for BPA and regularly conducting an assessment of electricity adequacy. On a five-year cycle, the NPCC and its staff experts prepare a twenty-year regional power plan that evaluates loads and supplies to determine the least cost resource needs for meeting future loads while maintaining system reliability. As part of this five-year cycle, the NPCC and its staff also prepare a Columbia River Basin fish and wildlife program to address the regional needs of fish and wildlife impacted by the federal hydropower system pursuant to the Northwest Power Act's requirement that this program mitigate and enhance the Basin's fish and wildlife resources, especially salmon and steelhead and provide "equitable treatment" for these resources while also ensuring an adequate, efficient, and economical regional power supply. Hydropower system operations to manage fish and wildlife issues are an important factor in the regional power planning analysis and are critical to assuring a reliable power system.

11. In 2011, the NPCC adopted a resource adequacy standard of 5-percent annual "loss of load probability" (LOLP) to determine if the region had sufficient resources to meet regional loads during periods of high demand on the system like winter cold snaps or summer heat waves or when major generating units like the nuclear plant at Hanford have to go off line for some reason. One of its tools to check adequacy by predicting the LOLP for different scenarios is a computer model that projects operations of the power system – both supply

[1] www.nwcouncil.org

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(including from the Columbia and Snake River dams) and demand – over many different future simulations (the GENESYS model). The GENESYS model (**Gen**eration **E**valuation **Sys**tem) was developed by NPCC in 1999 to replace earlier load-resource balance analysis. GENESYS uses a random probability analysis applied to a number of key variables, (e.g. loads, water levels, generation resources, energy efficiency) on a monthly operations basis. In 2019, the NPCC completed a substantial redevelopment of GENESYS to provide hourly analysis of operations, more granular/individual power plant dispatch, interactions between reserves and system optimized dispatch, and more interactive inclusion of regional and western power market dynamics.[2]

12. In 2022-2023, the NPCC recognized the increased complexity in the regional power system with more variable renewable energy resources, and a need for an even more sophisticated and precise approach to evaluate resource adequacy for the region. The NPCC made another round of significant changes to the GENESYS model and created a multi-metric adequacy framework to provide more detailed information about future demand and power supply needs to power system operators on the potential frequency, duration, and magnitude of shortfall events (i.e., time of high demand and limited supply) so they can plan for and mitigate risk with actions as well as determine the appropriate emergency measures to implement if necessary in order to avoid a significant loss of load (a power blackout of significant scope and duration).[3] This more sophisticated multi-metric approach has replaced the relatively simple

[2] https://www.nwcouncil.org/2021powerplan_genesys-model/

[3] https://www.nwcouncil.org/fs/18853/2024-4.pdf

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single metric LOLP approach in the NPCC's most recent analysis for its forthcoming Ninth Power Plan as described on the NPCC's Resource Adequacy webpage.[4]

13. In the most recent update in 2024, NPCC's Pacific Northwest Power Supply Adequacy Assessment for 2029 used this new multi-metric modeling approach[5] and included the hydrosystem operation commitments from the 2023 Resilient Columbia Basin Agreement (RCBA) that were implemented during the stay of litigation. These commitments made a number of changes to dam and river operations to better support fish recovery efforts at the eight lower Snake River (LSR) dams and the lower Columbia dams.

14. As NPCC has explained in this and previous adequacy assessments, predicted shortfalls or adequacy concerns using any metric "does not necessitate an actual blackout will take place."[6] A shortfall in the adequacy modeling would signal the need for additional actions to be taken to avoid power disruptions, such as increased market purchases, mobilizing back-up generation, ramping up higher cost generation, suspension of fish protection operations, or calls for energy conservation or curtailment.

15. What is noteworthy in the analysis for the Adequacy Assessment for 2029 are the significant changes the NPCC made to reflect the broad challenges of matching the power supply with demand across a wide range of possible futures facing the region. As can be seen in Figure 8, the NPCC staff made adjustments due to significant new load growth from data center development and electrification, new transmission line development, coal-to-gas power plant

[4] https://www.nwcouncil.org/energy/energy-topics/resource-adequacy/

[5] Ibid, page 9.

[6] Ibid, page 9.

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conversions, RCBA hydro operations, and new planned resources available to meet overall system needs.

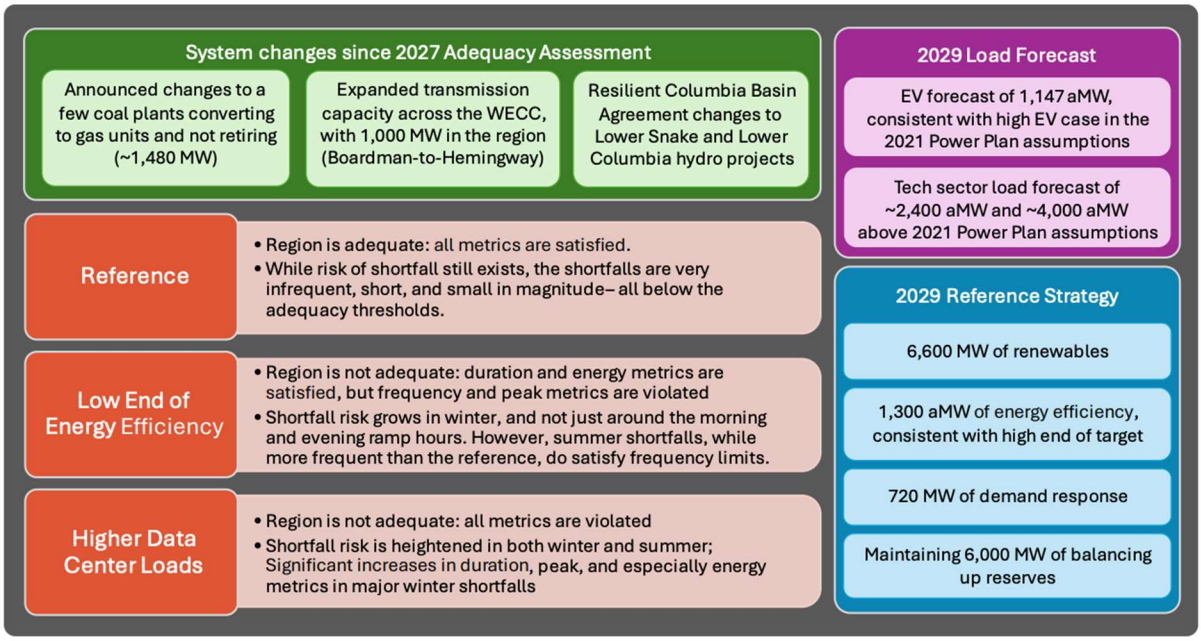


Figure 8. High-level summary of 2029 Adequacy Assessment

16. After including the RCBA operation changes to hydro operations, NPCC ran its power system adequacy assessment for 2029. The report states that "while hydropower is slightly reduced, …the changes do not lead to a significantly different regional adequacy result."[7] The model shows that the system adjusts to the RCBA dam and river operations by making a small increase in thermal generation and market purchases, particularly at night. The market purchases are within the market reliance limit set for the region. In the 2021 Power Plan, the NPCC set a power import limit to assure that the Northwest did not over rely on market purchases to satisfy resource needs.[8] Finding the RCBA operations are within the market reliance limit means that in

[7] Ibid, Page 22.

[8] https://www.nwcouncil.org/2021powerplan_change-reliance-extra-regional-markets-resource-adequacy/#:~:text=Our%20baseline%20setup%20limits%20the,Energy

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the NPCC's assessment, it is reasonable to assume that market purchases will be available to compensate for any small decrease in hydro generation due to RCBA operations in the context of the full system operations and regional demand.

17. The Adequacy Assessment for 2029 indicates that inclusion of the hydro operations from the RCBA are relatively insignificant given the magnitude of forecasted load growth changes and emphasizes the critical need for the region to accelerate deployment of energy efficiency, new renewable resource development and transmission system expansion. Further, the assessment concluded that the region could meet the NPCC's multi-factor reliability standards under all but two of the scenarios that were examined. The first assumes low acquisition of energy efficiency and the second assumes high case data center development (Table 7).[9]

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

18. For comparative purposes only, the NPCC staff note that if the multi-metric approach was compared to the LOLP, the reference case in the Adequacy Assessment for 2029,

[9] https://www.nwcouncil.org/fs/18853/2024-4.pdf, page 27.

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which includes the RCBA operations, would be a 2.2% LOLP. The low EE resulted in a LOLP of 7.8%[10] and the high data center scenario increased the LOLP to 13.3%.[11]

19. BPA's results are significantly different than the NPCC analysis. In Rachel Dibble's declaration[12] (para. 29), she describes BPA's use of GENESYS to determine the LOLP with different hydrosystem operations. In Table 1 (below) and in para. 31, Dibble concludes that all the hydrosystem operation scenarios would result in significant reliability challenges with LOLP's at 15% for the 2026 Fish Operations Program, 18% for the 2020 BiOp (called 2020 CRSO EIS ROD) and because the preliminary injunction "will reduce power generation and thus result in a higher LOLP: 27 percent."[13] Dibble goes on to clarify in para. 65, that the preliminary injunction results in a 250 MW reduction in power generation. Based on the review of the NPCC analyses it is unclear how the modest loss of generation results in such a dramatic increase in LOLP.

20. In fact, Dibble does not provide the assumptions, metrics, or scenarios that BPA used as inputs to GENESYS or the version of GENESYS that BPA used. Based on the output of the "LOLP" metric in BPA's results, which NPCC has replaced in the newer and more sophisticated version of GENESYS as discussed above, it appears that BPA may not have used the most recent multi-metric approach that NPCC now uses. Without meaningful or complete information on the assumptions, methods, or scenarios used in Dibble's modeling, it is

[10] Ibid, page 27.

[11] Ibid, page 28.

[12] 1404 2574 2025.12.16 Declaration of Rachel Dibble.pdf

[13] Ibid, Page 19, Para 31.

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impossible to determine why her modeling reached such different results from NPCC staff's comprehensive resource adequacy analysis and modeling of RCBA operations.

21. As a reminder, the NPCC Adequacy Assessment for 2029 shown in Figure 8 above states that the reference case was "below the adequacy thresholds" using an arguably more stringent RCBA hydro operations than BPA used in its Table 1 GENESYS modeling. The Adequacy Assessment for 2029 also assumes that the new resources identified in the NPCC's 2021 regional Power Plan[14] would be developed in a timely manner. This plays a significant role in ensuring that all the power supply adequacy metrics are met.[15]

22. Separate from this Adequacy Assessment for 2029, as part of the development of the Ninth Power Plan, the NPCC staff are beginning to evaluate future energy needs. As part of this work, NPCC staff recently modeled the effect of the impact of different hydrosystem operations for fish passage, coupled with the needs assessment, on power generation and reliability, among other metrics. In the NPCC staff Needs Assessment for Changing Hydro Operations Scenario, presented to the full Council on October 14, 2025[16], staff ran four different fish operation sensitivities against the 20-year forecasted needs of the power system through the updated GENESYS model. The four sensitivities analyzed by NPCC staff are: 2020 BiOp Operations ("current operations"); 2023 RCBA Operations; Fish managers Recommended Operations for MOP/spill (which is called "New MOP" and is virtually identical to the NWF's preliminary injunction request and Oregon's proposed preliminary injunction order); and Limited

[14] https://www.nwcouncil.org/fs/17680/2021powerplan_2022-3.pdf

[15] Pacific Northwest Power Supply Adequacy Assessment for 2029, NPCC 2024-4, page 35.

[16] https://www.nwcouncil.org/fs/19637/2025_10_1b.pdf

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Daily Flexibility (which starts with the 2020 BiOp as the base and then limits flexibility to reduce ramping).[17]

23. All of the fish operations analyzed including the "New MOP" sensitivity show very similar reliability results for power system operations, including the frequency and duration of events that risk a power supply shortfall. Critically, these winter and summer peak needs are extremely comparable across each of the modeled hydrosystem operations to address fish needs -- and the fish operation scenario that represents the preliminary injunction actually is predicted to perform *better* for reliability across seasons because the number of events and magnitude of the energy shortage events are lower for the New MOP than the BiOp or the RCBA using the "mixed bag" pathway with the 2031 load forecast, as shown in the chart below.[18]

Overall Results Compared to Metrics

	Frequency			Extreme Deficits		
	Annual LOLEV (events)	Winter LOLEV (events)	Summer LOLEV (events)	VaR Duration (hr)	VaR Peak (MW)	VaR Energy (MWh)
Adequacy Criteria	0.2	0.1	0.1	8	1,200	9,600
BiOp	218	61	75	22	9,681	354,192
RCBA	210	57	85	21	10,366	348,771
New MOP	189	59	55	21	8,917	326,858
Limited Flex	168	49	53	22	10,200	327,008

Northwest Power and Conservation Council 91 The 9th Northwest Regional Power Plan

Again, these predicted reliability events do not mean a blackout will occur. Instead, they are projected as part of power system planning to evaluate and prepare for the amount of proposed

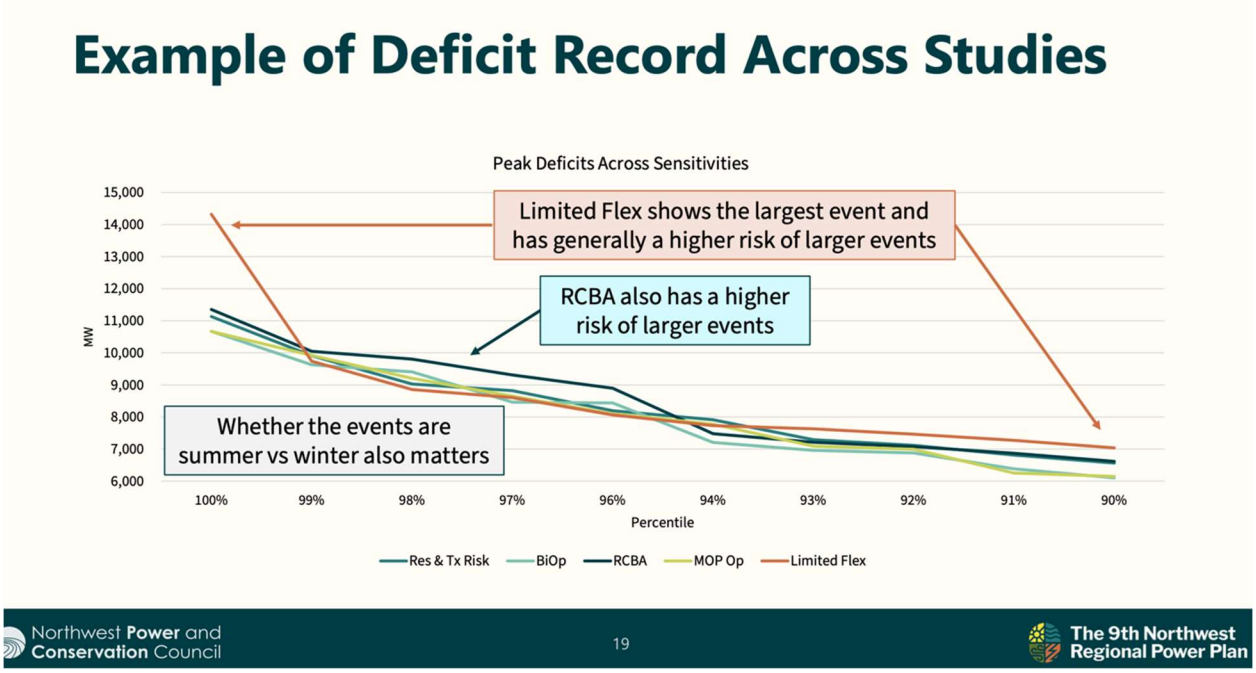
[17] https://www.nwcouncil.org/fs/19637/2025_10_1b.pdf (page 6).

[18] Ibid, Slide 91.

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new resource expansion or other power supply action (e.g., additional energy conservation) to address the events.

24. In January 2026, NPCC staff reran GENESYS after catching an error in irrigation demand.[19] This updated modeling shows similar results to the October 2025 hydro ops needs analysis which is that the region's projected large load growth will drive the need for new resources to meet winter and summer energy and peak capacity needs. On slide 19 (below), the revised modeling shows that the MOP sensitivity has fewer reliability events that are of less magnitude. This is a similar outcome to the October results.

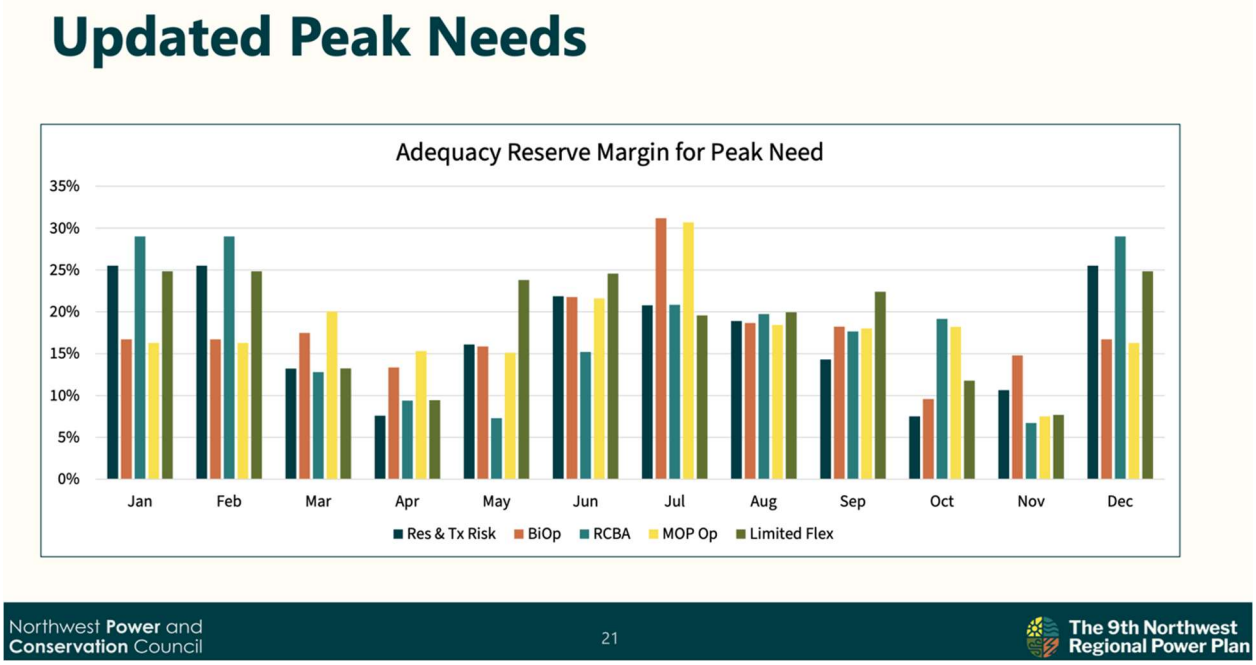


25. The NPCC staff go on to show how the corrected modeling impacts peak and energy needs across the year. While there are some variations across the different hydro operation sensitivities, the similarities are more striking than the differences. The New MOP operations do not create wildly different needs for additional peaking (Slide 21) or energy (Slide

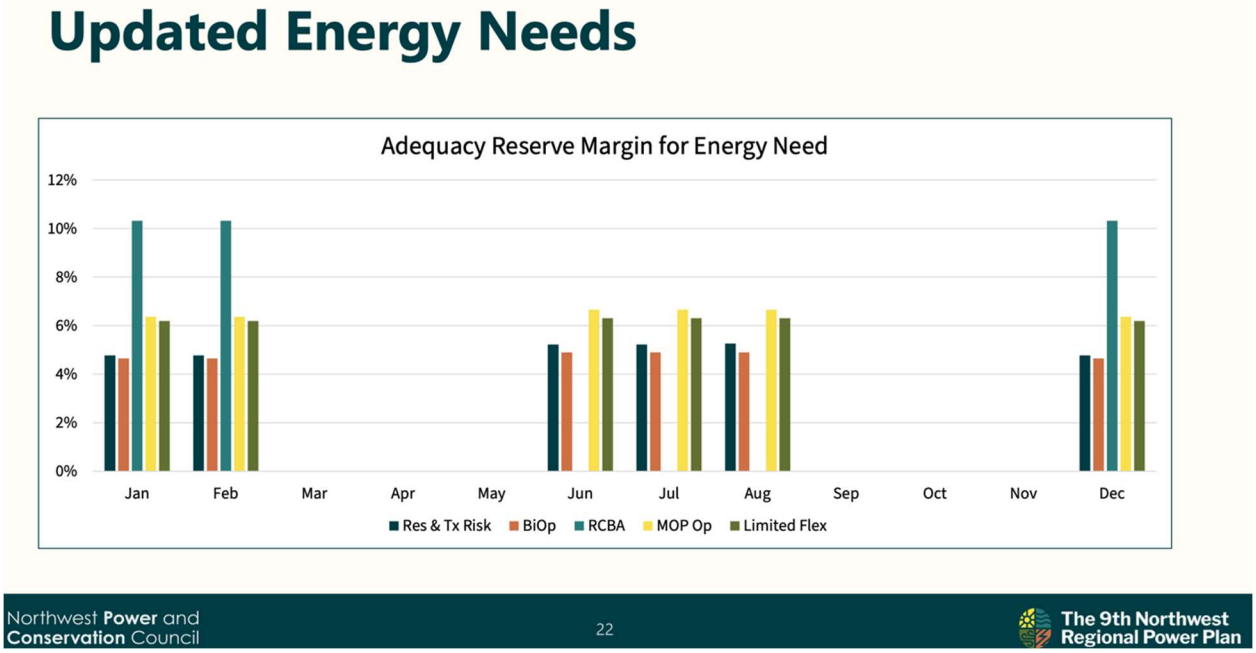
[19] https://www.nwcouncil.org/fs/19713/2026_01_3.pdf Pages 15-22.

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22) resources. As described in more detail below, this modeling shows that significant new resources will be needed over the long-term under any fish operations scenario, and that changes in demand (including changes driven by load growth, decarbonization, and data centers) are the drivers for these substantial long-term resource needs. The different fish operations scenarios do not significantly change the timing or magnitude of these long-term resource needs.



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26. As expected, there are still significant needs (because the resource addition model has not yet been run to solve for the shown need) in the winter and summer months. For all resource adequacy assessments, the modeling does not indicate that these reliability events will happen, just that there is a probability that they could happen and BPA and utilities should take steps to be prepared to manage the system (and add new resources as needed) to avoid these adverse impacts.

B. NPPC Analysis Shows that the Differences Between Fish Operations are Minor for Energy Needs and Peak Capacity Needs.

27. As part of the Ninth Plan development, NPCC staff put together a comprehensive needs assessment based on expected growth in loads from data centers, electrification and economic/population growth. It is expected that the needs assessment will indicate that the regional power system will need to develop thousands of megawatts of new resources to meet

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growing energy and winter and summer peak demands.[20] The range of hydrosystem operations from the 2020 BiOp, RCBA or proposed injunction do not materially affect the actions the region needs to take to meet projected future demand.[21] The resource needs assessment built into GENESYS is then fed into the NPCC OptGen model[22] which is a capacity expansion model and it helps determine what mix of resources are needed to meet the adequacy requirements. It is expected that the NPCC will use all these analytics to recommend, in the Ninth Power Plan, that the region and BPA add new generation, demand management, energy storage, and energy efficiency to the system.

28. In the Needs Assessment for Changing Hydro Operations Scenario, the NPCC staff did a detailed examination of how the hydrosystem responded to four different hydro operations sensitivities and how those sensitivities impacted the system-wide needs assessment across 90 different system scenarios. In addition to resource adequacy, the NPCC staff also looked at the energy and capacity generation across the hydrosystem operations.

29. From the chart on Slide 14 the differences in the four sensitivities are clearly delineated, showing that the differences are at most modest. The New MOP includes one month of additional spill in August at the LSR dams, and one to one-and-a-half foot operating ranges at the lower Columbia and LSR dams during the Spring and Summer salmon migration seasons.

[20] https://www.nwcouncil.org/fs/19637/2025_10_1b.pdf Slide 83.

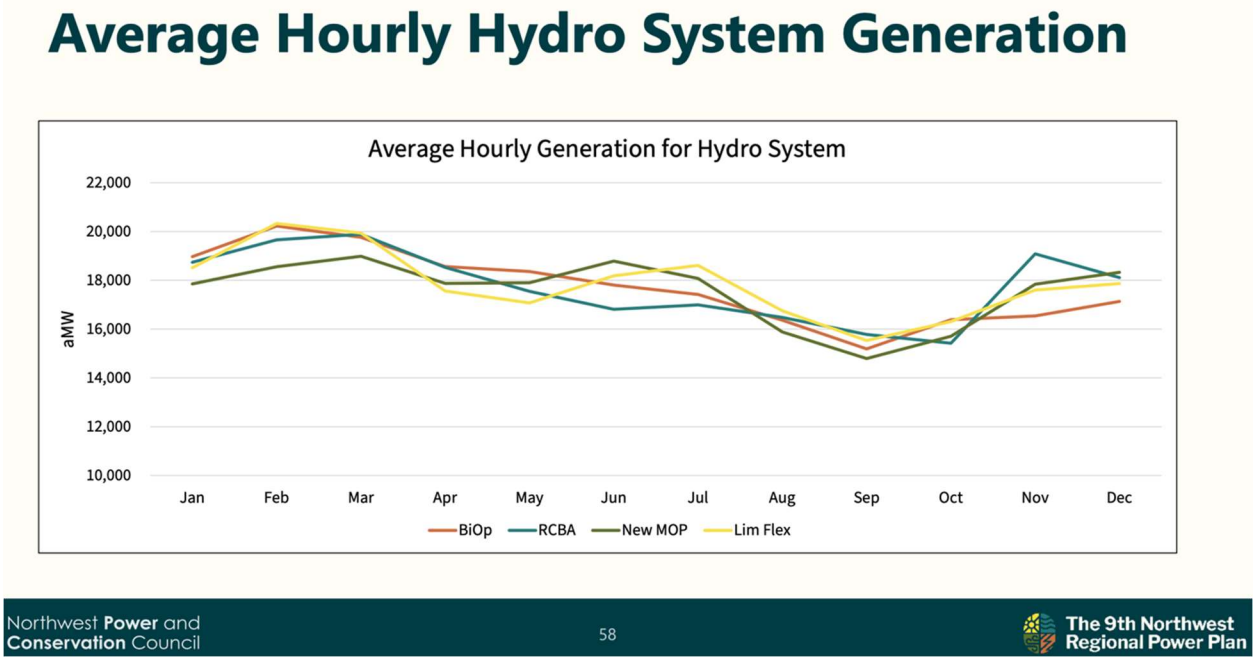
[21] Ibid, Slide 85.

[22] https://www.nwcouncil.org/fs/19331/2025_04_07.pdf

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Sensitivity	Min Elevation	Elevation Target Sof-Constraint	Elevation Target Hard Constraint	Spill	Outflow Ramp	Reserves Allocation
2020 BiOp	2025 Water Management Plan (WMP)			BiOp spill	2025 WMP	Existing
2023 RCBA				RCBA spill	2025 WMP	Existing
New MOP & Spill	2025 WMP	+1 lower Columbia + 0.5 Lower Snake	+1.5 lower Columbia + 1 Lower Snake	RCBA spill with Aug 30 date	2025 WMP	Existing
Limited Flex	2025 WMP			BiOp Spill	2020-2024 avg.	Half

30. For the system as a whole, the NPCC analysis shows very modest difference in average hourly energy generation between the different fish operations.[23] The New MOP is slightly lower than the BiOp in January-April and September, but higher than the BiOp in May-July and November-December. The differences in all cases represent a small percentage of the total generation of the regional and federal power systems.

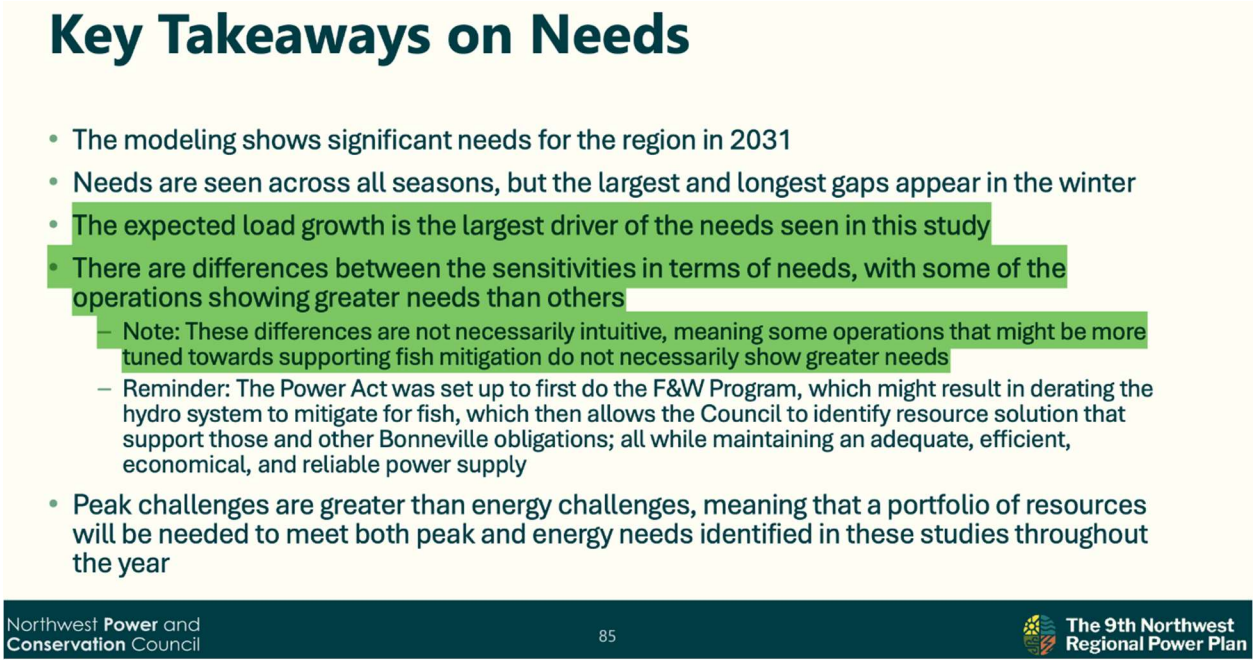


31. The NPCC Ninth Power Plan, which is under development and should be finalized in late 2026, is designed to assess existing and planned resources and the gap between

[23] Ibid, Slides 58 and 59.

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forecasted growth in demand and existing/planned resources.[24] The Ninth Plan will then recommend a portfolio of new resources to meet the forecasted demand growth and maintain a reliable power system. Projected load growth in power demand from data centers and electrification are the leading drivers of the need for new resources in the NPCC staff hydro operations and needs assessment. The analysis notes that some of the hydro operations that support fish recovery do not lead to greater resource needs.[25]



C. BPA has Many Tools to Provide Flexibility, Balancing and Operational Reserves

32. BPA operates 31 hydro projects as part of the federal hydrosystem across the region and has used all of the significant system flexibility to manage hydro operations for different fish survival regimes over the past decade to meet energy and capacity needs. In addition to the daily system operations activity that the BPA staff manage to provide a reliable

[24] https://www.nwcouncil.org/energy/ninthpowerplan/

[25] https://www.nwcouncil.org/fs/19637/2025_10_1b.pdf, Slide 85.

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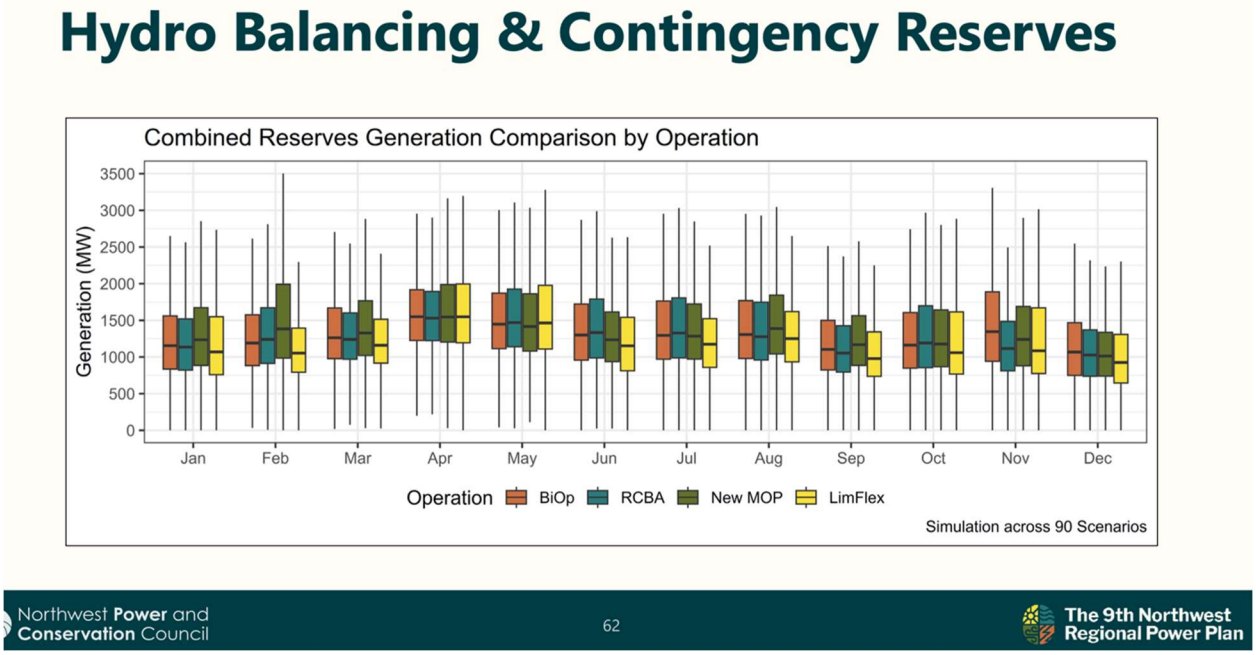
power system through many different kinds of system and operational constraints, there are other tools that BPA has and does use within and outside the federal system. These tools include, among others: Western Energy Imbalance Market, Fish Operations Plan variances, adding new strategic resources, and declaring an emergency. The point is, BPA has access to system flexibility and other flexibility tools to meet the kind of short duration supply constraints that the most recent NPCC modeling predicts under any hydro operations system while the agency and the region builds out new resources to meet load growth.

33. A key priority in system management is ensuring reserves. The NPCC hydro operations analysis in Slide 62 below shows very little difference across the four fish sensitivities and the 90 different simulation scenarios in terms of meeting requirements for overall system balancing and contingency reserves. February is the exception and it actually shows more generation across 90 scenarios from New MOP/preliminary injunction operations.[26] BPA's McManus' statement that there will be significant impact on balancing reserves (Page 8) is not evident in the NPCC modeling.[27]

[26] https://www.nwcouncil.org/fs/19637/2025_10_1b.pdf, Slide 62

[27] 1404 2579 2025.12.16 Declaration of Bartholemew McManus.pdf

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34. Interestingly, the LimFlex sensitivity, that the NPCC staff model, reduces the reserve allocation by half for the eight projects being impacted by fish operations (see the chart above at my para 26). In other words, for this modeling exercise, the NPCC staff assumes strict limits on the flexibility of these projects, and as a result they cannot provide as much reserve to the system. In the model, BPA still holds the same 4,000 MW of total reserve but not at these eight projects. NPCC staff note that the reserve needs are taken up in other places in the system.[28] This is evident in the results as the LimFlex contingency and operating reserves are not significantly different from the other operations, despite the limitation on flexibility (Slide 62 above). I do note that LimFlex is slightly more limited in the winter when water flows are more constrained. Overall, this indicates that BPA would be using the other tools at its disposal to address operational changes and in fact has been using those tools.

[28] Vimeo.com/1127583111 – starting time at 30:37 to 34:00

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35. One of the most important tools available for meeting real-time energy balancing is the Western Energy Imbalance Market (WEIM) which includes 22 utilities across the West.[29] In the WEIM utilities and system operators can buy and sell power for load imbalances within fifteen-minute and five-minute intervals within an hour. This is a substantial market tool that provides significant support for balancing and flexibility needs. BPA joined the WEIM in 2022 and has seen significant financial and system operational benefits both in terms of purchasing power when demand spikes or when there is extreme weather and in terms of selling power to others when BPA has surplus supply to help with balancing the system. In fact, BPA's gross benefits from participation in the WEIM are equal to $25-$35 million/year.[30] It is notable that none of the BPA declarations by Dibble, McManus or Stevenson make mention of this important development for balancing power supply and demand.

36. Another tool to assist BPA with system operations are the variances and pre-coordinated operational changes used as part of the annual Fish Operation Plan (FOP) implementation. Attached hereto as Exhibit A is an Excel spreadsheet that summarizes my review of the data on variance and pre-coordinated operational changes for the past six years (2020 to 2025) to see how often variances and other operational changes were used to address energy or transmission (energy) related challenges.[31] The annual FOP reports show implementation changes from April to August in each year. The reasons for variances include human and program error, maintenance, navigation, and debris issues. The reasons for pre-coordinated operational changes include maintenance, navigation and transmission reliability.

[29] https://www.westernenergymarkets.com/western-energy-imbalance-market-weim

[30] https://www.westernenergymarkets.com/western-energy-imbalance-market-weim/benefits

[31] https://public.crohms.org/tmt/documents/FOP_Implementation_Reports/

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All of these increases or decreases in spill occur at one hour increments up to 24 hours in a particular day. For the transmission reliability operational changes, the increases in spill are "to provide reserves." And the decreases in spill are "due to an increase in generation to deploy reserves."[32]

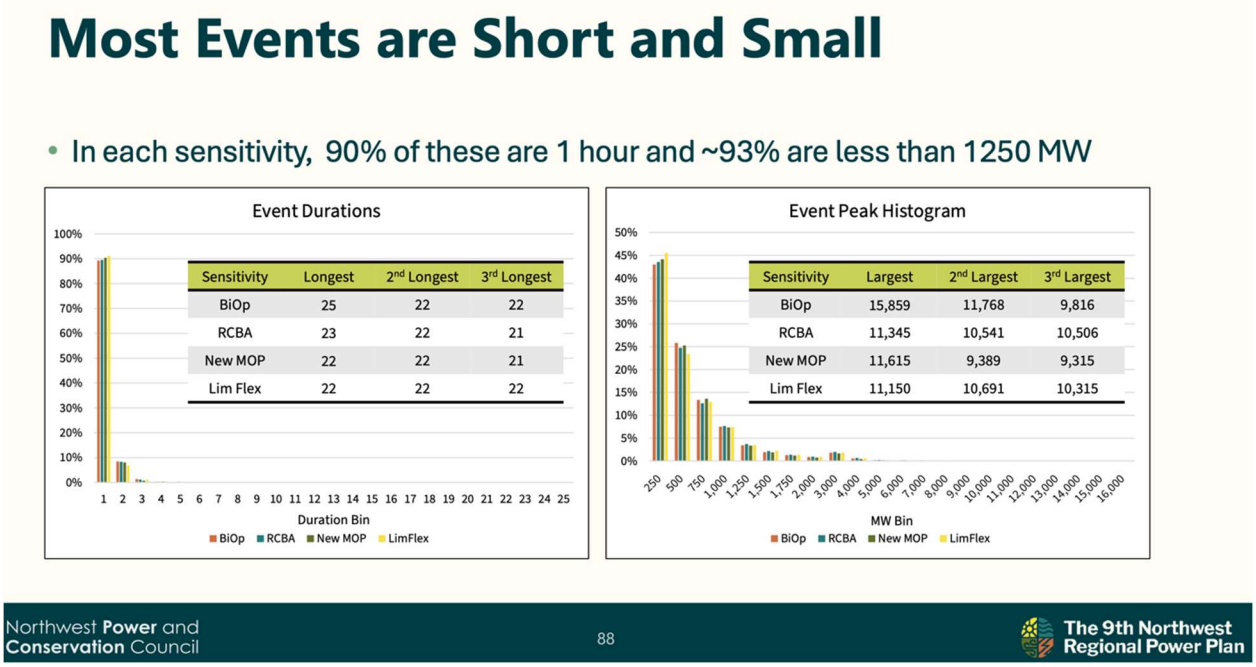
37. What is fascinating about this data is that spill operations were adjusted 3,786 hours during the five-year period for human/program error, maintenance, navigation, and debris management. Whereas spill operations were adjusted 483 hours during the five-year period for transmission reliability reasons. In 2024 and 2025, when the RCBA operations were in place, energy related changes occurred in only two hours in the period between April-August. Whereas in this same timeframe, the other reasons for change required 1,439 hours of variances and pre-coordinated changes.

38. The FOP variance data shows that many of the variances and pre-coordinated operational changes needed are for an hour. There is an interesting correlation between the use of the variances and changes and the NPCC hydro ops needs assessment which says that 90% of these reliability events are one hour in duration with another 8% at two hours in duration. Across the entire power system, 70% of the events are less than 500 megawatts and 93% of events are less than 1250 megawatts.[33] This indicates that routine short-duration variances may continue to be a useful tool to allow adjustments to meet any of the short-duration challenges that occur on BPA's system.

[32] Ibid, Page 6.

[33] http://nwcouncil.or/fs/19637/2025_10_1b.pdf Slide 88.

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39. While it has been clear for some time that BPA and other utilities in the region will need to add new resources to maintain resource adequacy in the face of load growth and other long-term challenges facing the region, BPA has surprisingly not taken significant action to add new power system resources. Section 6 of the Northwest Power Act authorizes BPA to acquire new resources to meet its needs, including its fish and wildlife protection operations.[34] New resources developed under this authority would provide more system flexibility and minimize the occurrence of emergencies in the future.

40. Top of the list for new resources is maximizing energy efficiency and working with BPA customers to manage loads to reduce peaks. The potential for regional demand management development (to reduce peak demand and provide dispatchable resources during capacity needs) is very substantial. Since 2010 and the 6th Power Plan, the NPCC has been calling on BPA and the region to make investments in demand management (often called

[34] 839d(a)(2)(B). to assist in meeting the requirements of section 839b(h) of this title. [Northwest Power Act, §6(a)(2)(B), 94 Stat. 2717.]

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demand response). The NPCC's 2021 Plan ramped this call up even more with estimates of about 3,721 megawatts of summer load reduction potential and 2,761 megawatts of winter load reduction potential.[35] A large portion of NPCC's recommended demand response resources consist of rate design and conservation voltage reduction programs that can be implemented quickly and very inexpensively over the next several years. This recommendation is expected to be strengthened in the 9th Plan as the region considers increased pressure on Northwest resource adequacy and sufficient flows in the hydrosystem for fish and wildlife protection. Despite the long-standing push from the NPCC, BPA's 2022-27 Energy Efficiency Action Plan noted 300 MW of demand response resources, but made no commitment to achieve these flexibility resources, and only to engage with its customer utilities in exploring opportunities.[36]

41. Another critical new resource is battery storage. In the past 5-6 years, both Texas and California have added thousands of megawatts of battery storage to their systems to manage peak energy needs. Texas now has 15,000 MW.[37] California has grown its battery storage resource from 800 MW in 2019 to 17,000 MW in 2025.[38] Most of this storage in California is from utility scale systems. Within the region, between 2022 and mid-2025, Portland General Electric has moved forward with a total of 492 MW of battery storage capacity in four different facilities across its service territory to provide up to four hours of peak energy or to support PGE's system during extreme weather or unexpected disruptions.[39] While the Northwest has

[35] https://www.nwcouncil.org/2021-northwest-power-plan/ Page 64.

[36] https://www.nwcouncil.org/fs/18206/2023_03_p3.pdf

[37] https://ieefa.org/resources/summer-solar-and-battery-storage-records-texas

[38] https://www.energy.ca.gov/news/2025-11/californias-battery-storage-fleet-continues-record-growth-strengthening-grid#:~:text=WHAT%20YOU%20NEED%20TO%20KNOW,Gov.

[39] https://portlandgeneral.com/news/2025-08-pge-energizes-475-mw-of-battery-energy-storage-to-boost-grid

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historically used the reservoir system as our utility scale storage battery, the writing has been on the wall for the past decade that that flexibility and capacity is increasingly constrained due to climate impacts on precipitation patterns, the needs of salmon and steelhead, and the needs to integrate variable renewable resources. Yet, BPA and much of the region have been very slow to develop battery storage projects, even short duration systems, to support fish operations and peak energy needs.

42. Throughout Dibble's declaration she states that BPA's only option to address the system flexibility needs and assure system reliability is to declare an emergency and suspend fish operations. I understand that the emergency protocols are available for emergencies to maintain power system reliability and are not intended as a way to provide regular operational system support. NWF's motion assumes that the emergency protocols remain in place and are a key tool to maintain reliability as are the more routine variances discussed above that do not require a declaration of power system emergency. By emphasizing the need for and consequences of an emergency declaration, BPA seems to overplay the loss of flexibility and ignore the flexibility created by other tools, from the WEIM to variances to changes across the rest of the system's operations.

D. The System Balancing Interaction Between LSR and the Lower Columbia Projects

43. I have reviewed a study conducted by the Pacific Northwest National Laboratory (PNNL) on the role of the four lower Snake River dams over a five-year time frame.[40] PNNL's analysis of operations at the four LSR dams, and the other mainstem Columbia dams over the 2020-2024 timeframe included fish operations in place during each of the study years. These

[40] September 2025, US Department of Energy, Lower Snake River Dams Contribution to Grid Services, https://www.osti.gov/biblio/3000013

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operations included years when the 2020 BiOp operations and the RCBA operations were in place.

44. In the chapters on inter and intra hour ramping and balancing, PNNL shows that there is great consistency in the operation of the lower Columbia, LSR, Grand Coulee, and Chief Joseph projects to provide system flexibility across the five-year period and different hydro operations for fish recovery. The most significant variables to how the different projects are operated are energy market conditions and water levels, not reservoir elevations and spill regimes.[41]

E. Supporting the Tri-Cities

45. Providing reliable support service to the local load center of the Tri-Cities is vitally important. Ice Harbor generators provide voltage and reactive power support to the Tri-Cities. This type of support makes the power system more efficient, helps control and manage the oscillation in voltage that exists in an AC system and comes from synchronous generators like those at Ice Harbor. The PNNL study finds that "most, if not all synchronous generators operate in Automatic Voltage Regulation mode".[42] Voltage regulation and reactive power support are more a function of the physical presence of the generators at Ice Harbor dam rather than the level of spill or MOP conditions at Ice Harbor. Stevenson also recognizes the important role of Ice Harbor in providing support to the Tri-Cities[43], though her examples imply the loss of generation at Ice Harbor. The preliminary injunction in no way contemplates this outcome. In

[41] Ibid, Chapters 3.0 and 4.0

[42] Ibid, page 38

[43] 1404 2582 2025.12.16 Declaration of Audrey Stevenson.pdf Paragraphs 17 and 33.

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addition, reactive power could be provided by locally sited storage and distributed generation, that may have fast response times and could provide additional reactive power support.[44]

46. Another option to support the Tri-Cities is grid enhancements, and BPA is already moving forward with some of these projects. However, the reliability support for the Tri-Cities has been a concern since the mid-2010s and it was not until 2023 that BPA launched the Tri-Cities Reinforcement Project.[45] The series of three grid reinforcement projects are very important and will help address these local reliability issues. Even before these projects are completed, however, the analysis performed by PNNL and the NPCC shows that power services to in the Tri-Cities will not be at risk from the preliminary injunction and that there are other resources that could be quickly deployed to address BPA's concerns.

F. Extreme Weather Events

47. Extreme weather events, both heat domes and arctic blasts, can happen in the Northwest and system reliability is vital during these challenging times. Recent experience has shown that extreme weather conditions do not usually occur across regions at the same time which allows the Northwest, California and the Southwest to share resources on the transmission interties and through the Western Energy Imbalance Market. This type of connectivity and coordination is important and BPA has planned for and effectively used these resources across regions during extreme events.

48. The PNNL study, for example, examined how BPA managed its system during the Northwest extreme winter event (January 2024 with RCBA fish operations in place). During

[44] https://rmi.org/clean-energy-101-how-batteries-can-support-grid-reliability/

[45] https://www.bpa.gov/-/media/Aep/efw/nepa/active/south-of-tri-cities/Tri-Cities-Reinforcement-Project-Fact-Sheet-2023-FINAL.pdf

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the January 2024 arctic blast, Pacific Northwest loads went up dramatically and PNNL shows that BPA responded by ramping up generation at Grand Coulee from 2,000 MW to 3,500 MW and at Chief Joseph from 1,000 MW to 2,000 MW during time of peak demand (generally morning and evening hours). Low water conditions are normal in winter in the lower Snake River basin and the LSR dams provided their typical level of increased winter generation during a cold snap – about 1,000 MW total for specific peak hours within each day.[46] PNNL states that "due to water constraints, the LSR plants were unable to significantly increase their output beyond typical levels but still contributed approximately 1,000 MW during peak generation".[47]

49. BPA used the ramping flexibility of its system to increase generation for a couple of hours at a time during these extreme emergency situations. The PNNL study also shows the crucial importance of interconnection within the West as BPA used the WEIM to bring 3,675 MW of power north on the California-Oregon Intertie – more power than the winter hydrosystem could provide under any circumstances.[48]

50. In the Dibble declaration, there is extensive reference to extreme weather events and the risk to public health and safety. As demonstrated in the PNNL analysis, BPA has many tools available to manage extreme weather events, including emergency protocols that allow suspension of fish operations to ensure reliability of the system. BPA has successfully used the WEIM power market to both bring resources into the northwest during extreme weather events and to send power to other parts of the west during their weather events.

[46] Ibid, Page 58, Figure 7-3

[47] Ibid, Page 56

[48] Ibid, Page 59, Figure 7-6

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G. Affordability

51. As I mentioned already, Dibble states that the proposed injunction operations will result in a loss of 250 average MW of power generation in fiscal year 2026. BPA's 2025 White Book[49] shows its total firm obligations to be approximately 8,000 aMW (with a high of 9,374 a MW in December and a low of 7,038 aMW in May).[50] Dibble's estimated lost generation of 250 aMW is approximately 3% of the yearly average MW generation for BPA. The White Book uses RCBA for hydro operations and the results state that in median water (50th percentile of system operations) there are annual energy surpluses throughout the 10-year planning period. However, BPA uses the 10th percentile of water flows (i.e., very low flow conditions) as its firm water conditions which results in annual deficits of 426 aMW to 1012 aMW.

52. In May 2025, BPA issued a letter to all Pacific Northwest utilities, and customers including outside the region customers, stating that it is "projecting that periodically through September 2026 BPA may have surplus power, capacity, and Transferred Frequency Response (TFR) available for sale."[51] While this notice is an annual notice of potential surplus resources, it is an indication that BPA has significant flexibility in how it utilizes the system to meet reliability requirements while also making additional sales to support increased revenue. Were BPA seriously concerned about the 15-27% LOLP presented in Dibble's declaration, this letter seems unusual at best.

53. On January 30, 2024, BPA Administrator John Hairston testified before the House Energy and Commerce Committee, Subcommittee on Energy, Climate and Grid Security

[49] https://www.bpa.gov/-/media/Aep/power/white-book/2025-whitebook.pdf

[50] Ibid, Pages 15-16.

[51] https://www.bpa.gov/-/media/Aep/power/power-products-catalog/fy-26-notice-of-surplus-power.pdf

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regarding the RCBA agreement and the impact on BPA.[52] Attached to Mr. Hairston's testimony is a spread sheet with BPA's preliminary rate assessment of the $300 million commitment in the RCBA combined with the rate impact of the operational changes in that agreement indicated an incremental rate impact per year of 0.05%. This increases power rates by $0.2 to $0.3/megawatthour. This spread sheet shows a line item for "Ops Ave. Revenue Increase" to estimate the financial impact of the operations included in the RCBA or stay of litigation. BPA estimated these rate impacts as generating an extra $1 million per year relative to the 2020 BiOp Record of Decision – in other words, BPA would *save* money by implementing these operational changes. The RCBA on the whole would impose only modest costs when the savings from changed operations are combined with the financial commitments BPA made in that agreement (which are addressed as separate line items in that spreadsheet, including "High Priority CBRI" and Lower Snake Comp Plan", together totaling $300 million over 10 years. BPA has abandoned the financial commitments in that agreement so the $300 million in increased costs over ten years are no longer affecting rates.[53]

Conclusions

54. Throughout Dibble's declaration, she uses significant hyperbole stating that the unprecedented proposed preliminary injunction will lead to power shortages and blackouts that will risk human health and safety and have significant economic damage to the region. Yet, after reviewing the NPCC Adequacy Assessment for 2029, the PNNL LSR assessment and the NPCC hydro operations analysis I conclude that the impact of the various fish operation regimes,

[52] https://www.energy.gov/sites/default/files/2024-01/January%2030%202024%20HEC%20BPA%20John%20Hairston%20Testimony%20Columbia%20River%20System_Final.pdf

[53] Ibid, Page 8 (page 2 of the spreadsheet).

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including those NWF seeks in its preliminary injunction, have very modest impacts on power generation, peak needs, and overall ability to maintain a reliable power system. The preliminary injunction operations are similar to previous operations of the system over the past five years with some modest adjustments in spill and operating pool elevations to reduce the harm to migrating salmon and steelhead. BPA has experience with the spill and MOP conditions and has experience managing the power system with these conditions and providing the flexibility necessary to match power supply with demand. And if emergencies arise, the protocols for modifying fish operations remain available.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge.

Executed this 22nd day of January, 2026.



NANCY HIRSH

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EXHIBIT 118

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

Bonneville
POWER ADMINISTRATION

In reply refer to: BPA-2026-01021-F (Sallomi)

February 19, 2026

SENT VIA EMAIL ONLY TO: Megan.Sallomi@atg.wa.gov

Megan Sallomi
Assistant Attorney General
Environmental Protection Division
Washington State Attorney General's Office
800 5th Ave., Suite 2000, TB-14
Seattle, WA 98104-3188

Dear Ms. Sallomi,

The Bonneville Power Administration (BPA) received your request for agency records made via the Freedom of Information Act, 5 U.S.C. § 552 (FOIA). BPA received your request on January 22, 2026, and assigned it tracking number BPA-2026-01021-F. Please use that tracking number in all communications with the agency regarding your FOIA request. This communication is the agency's formal acknowledgement of and response to your request.

Request
"The time period for the request noted below is January 20, 2025, to the date the Bonneville Power Administration processes this request. All documents or communications concerning,

> (A) the existence of emergency conditions in the Western Electricity Coordinating Council Northwest region; or
> (B) Bonneville's role as the Balancing Authority for purposes of the Department of Energy Order No. 202-25-11."

Acknowledgement
BPA reviewed your request and determined it fulfills all criteria of a proper request under the FOIA and U.S. Department of Energy (DOE) FOIA regulations at Title 10, Code of Federal Regulations, Part 1004.

Fees
You seek a fee waiver. Your fee waiver request is granted. No fees will be associated with processing your FOIA request.

Response
Knowledgeable subject matter experts in the agency's Transmission System Operations organization searched for and found no records responsive to your request. Knowledgeable staff explained that BPA is not the balancing authority for TransAlta Centralia Generation ("Centralia"), and Energy Order No. 202-25-11 named BPA in error. Gridforce Energy Management is the balancing authority for Centralia. You may access records that memorialize this at the Federal Energy Regulatory Commission eLibrary: Gridforce Energy Management, LLC submits FERC Form 714 report for 2024/Q4.

Fees
No fees are associated with processing your FOIA request.

Certification
Pursuant to 10 C.F.R. § 1004.7(b)(2), I am the individual responsible for the records search and response described above. Your records request is now closed with no responsive agency information available to provide.

Appeal
The FOIA response certified above is final. Pursuant to 10 C.F.R. § 1004.8, you may appeal the adequacy of the records search, and the completeness of this final release, within 90 calendar days from the date of this communication. Appeals should be addressed to:

Director, Office of Hearings and Appeals
HG-1, L'Enfant Plaza
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585-1615

The written appeal, including the envelope, must clearly indicate that a FOIA appeal is being made. You may also submit your appeal by e-mail to OHA.filings@hq.doe.gov, including the phrase "Freedom of Information Appeal" in the subject line. (The Office of Hearings and Appeals prefers to receive appeals by email.) The appeal must contain all the elements required by 10 C.F.R. § 1004.8, including a copy of the determination letter. Thereafter, judicial review will be available to you in the Federal District Court either (1) in the district where you reside, (2) where you have your principal place of business, (3) where DOE's records are situated, or (4) in the District of Columbia.

Additionally, you may contact the Office of Government Information Services (OGIS) at the National Archives and Records Administration to inquire about the FOIA mediation services they offer. The contact information for OGIS is as follows:

Office of Government Information Services
National Archives and Records Administration
8601 Adelphi Road-OGIS
College Park, Maryland 20740-6001

E-mail: ogis@nara.gov
Phone: 202-741-5770
Toll-free: 1-877-684-6448
Fax: 202-741-5769

Questions about this communication may be directed to James King, FOIA Public Liaison, at jjking@bpa.gov or at 503-230-7621.

Sincerely,

Candice D. Palen
Freedom of Information/Privacy Act Officer

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

In reply refer to: BPA-2026-01019-F

March 12, 2026

SENT VIA EMAIL ONLY TO: Megan.Sallomi@atg.wa.gov

Megan Sallomi
Assistant Attorney General
Environmental Protection Division
Washington State Attorney General's Office
800 5th Ave., Suite 2000, TB-14
Seattle, WA 98104-3188

Dear Ms. Sallomi,

This communication is the Bonneville Power Administration's (BPA) first partial response to your request for agency records made under the Freedom of Information Act, 5 U.S.C. § 552 (FOIA). Your request was received on January 22, 2026, and formally acknowledged on February 24, 2025.

Original Request
"The time period for the request noted below is January 20, 2025, to the date the Bonneville Power Administration processes this request. All e-mails, documents, or other communications that contain any reference to the TransAlta Centralia Generation Station in Washington State. This includes any documents or e-mails that contain the key words: TransAlta; Centralia; or '202-25-11.'"

Clarifications
Via email exchanges had with the agency from January 22, 2026, to February 19, 2026, you and the agency agreed to amend your records request scope as follows: "The time period for the request noted below is January 20, 2025, to the date the Bonneville Power Administration processes this request. […] We would like documents that contain any one of the three search terms, so (TRANSALTA) (OR) (CENTRALIA) (OR) (202-25-11). Specifically to include the following preliminary searches results:

- 73 ALLBPA ((TRANSALTA) (c:s) (CENTRALIA) (c:s) ("202-25-11")) (c:c) (Kind=email) AND (Date=2025-11-01..2026-01-23) AND (Participants:*@hq.doe.gov)
- 349 3 in K + SLB ((TRANSALTA) (c:s) (CENTRALIA) (c:s) ("202-25-11")) (c:c) (Kind=email) AND (Date=2025-11-01..2026-01-23)"

First Partial Response
Using the search criteria described above, BPA's Cyber Forensics team collected records from the agency's email system. While conducting our preliminary review to ensure the records collected are responsive to your request, we noted that the records fall into four categories:

1) The agency receives Order No. 202-25-11 from the Department of Energy (DOE) and circulates the order among agency staff.
2) Agency staff discuss the Order as it relates to BPA and determine that TransAlta is not in the agency's balancing authority. As confirmation, staff pointed to Gridforce Energy Management, LLC's FERC filing: Gridforce FERC Form 714. (**Note**: We provided this information to you in our formal response to your FOIA request with tracking number BPA-2026-01021-F.)
3) Agency staff discuss inquiries from external parties about the Order and how to respond.
4) Agency staff draft a statement to explain BPA's role relating to the Order.

To provide an efficient response to your request, we are releasing four email records to demonstrate the chain of events described above as a first partial response. Further, we are seeking your input on whether you would like us to process the remaining records that were collected or if the partial response satisfies your request.

Eight pages accompany this communication with minor redactions applied under 5 U.S.C. § 552(b)(6) (Exemption 6). This exemption serves to protect Personally Identifiable Information contained in agency records when no overriding public interest in the information exists. BPA does not find an overriding public interest in the release of the information redacted under Exemption 6—specifically, cell phone numbers. This information sheds no light on the executive functions of the agency and BPA finds no overriding public interest in its release. BPA cannot waive these redactions, as the protections afforded by Exemption 6 belong to individuals and not to the agency.

Certification
Pursuant to 10 C.F.R. § 1004.7, I am the individual responsible for the records search and information release described above.

Appeal
As noted above, the records release certified above is partial. Pursuant to 10 C.F.R. § 1004.8, you may appeal the adequacy of the records search, and the completeness of this partial release, within 90 calendar days from the date of this communication. Appeals should be addressed to:

Director, Office of Hearings and Appeals
HG-1, L'Enfant Plaza
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585-1615

The written appeal, including the envelope, must clearly indicate that a FOIA appeal is being made. You may also submit your appeal by e-mail to OHA.filings@hq.doe.gov, including the phrase "Freedom of Information Appeal" in the subject line. (The Office of Hearings and Appeals prefers to receive appeals by email.) The appeal must contain all the elements required by 10 C.F.R. § 1004.8, including a copy of the determination letter. Thereafter, judicial review will be available to you in the Federal District Court either (1) in the district where you reside, (2) where you have your principal place of business, (3) where DOE's records are situated, or (4) in the District of Columbia.

Additionally, you may contact the Office of Government Information Services (OGIS) at the National Archives and Records Administration to inquire about the FOIA mediation services they offer. The contact information for OGIS is as follows:

Office of Government Information Services
National Archives and Records Administration
8601 Adelphi Road-OGIS
College Park, Maryland 20740-6001
E-mail: ogis@nara.gov
Phone: 202-741-5770
Toll-free: 1-877-684-6448
Fax: 202-741-5769

Next Partial Release Date
As explained above, we are seeking your input on whether you would like us to process the remaining records that were collected. Once we have that input from you, we will provide an estimated completion date.

Questions about this communication may be directed to James King, FOIA Public Liaison, at jjking@bpa.gov or at 503-230-7621 or Jason Taylor, FOIA Program Lead, at jetaylor@bpa.gov or 503-230-3537.

Sincerely,

Candice D. Palen
Freedom of Information/Privacy Act Officer

Responsive agency information accompanies this communication.

From:	Baskerville,Sonya L (BPA) - AI-WASH
To:	Emily Burdick; Tatulyan, Kevin
Cc:	Ardis, Melissa; Chong Tim,Marcus H (BPA) - L-7
Subject:	Order re Centralia
Date:	Wednesday, December 17, 2025 7:03:22 AM
Attachments:	order-number-202-25-11.pdf
Importance:	High

Hello, all. BPA has become aware of the attached order related to Centralia, and had been aware that TransAlta and PSE have plans to restart Unit 2 to run on natural gas.

It would be good to have a briefing from DOE to ensure we have a common understanding of BPA's role in this order. It appears that this would be operations as usual once the plant is restarted running natural gas. (Power flowing within the BA). Because there was specific direction in the order, which would typically suggest action outside of normal operations, it's unclear whether the order is seeking something new or different? It would be good to make sure we understand the intent.

Thanks.

SONYA BASKERVILLE
BONNEVILLE POWER ADMINISTRATION
DEPARTMENT OF ENERGY
Director | Intergovernmental Affairs
slbaskerville@bpa.gov
O: 202-586-5587 | C: (b) (6)

Taylor,Jason E (BPA) - CGI-7

From: Hairston,John L (BPA) - A-7
Sent: Friday, January 9, 2026 12:06 PM
To: Miller,Mike P (BPA) - T-DITT-2; Baskerville,Sonya L (BPA) - AI-WASH; Cooper,Suzanne B (BPA) - K-7; Chong Tim,Marcus H (BPA) - L-7; Scruggs,Joel L (BPA) - NK-7; Wingert,Kevin M (BPA) - NKP-7
Cc: Bustamante,Richard (BPA) - TO-DITT-2; Manary,Michelle L (BPA) - TS-DITT-2; Van Calcar,Pamela M (BPA) - PG-5; Cook,Jeffrey W (BPA) - TP-DITT-2
Subject: RE: Order re Centralia

Thanks, Sonya, for getting this clarification!

John

From: Miller,Mike P (BPA) - T-DITT-2 <mpmiller@bpa.gov>
Sent: Friday, January 9, 2026 12:05 PM
To: Baskerville,Sonya L (BPA) - AI-WASH <slbaskerville@bpa.gov>; Hairston,John L (BPA) - A-7 <jlhairston@bpa.gov>; Cooper,Suzanne B (BPA) - K-7 <sbcooper@bpa.gov>; Chong Tim,Marcus H (BPA) - L-7 <mhchongtim@bpa.gov>; Scruggs,Joel L (BPA) - NK-7 <jlscruggs@bpa.gov>; Wingert,Kevin M (BPA) - NKP-7 <kwingert@bpa.gov>
Cc: Bustamante,Richard (BPA) - TO-DITT-2 <rxbustamante@bpa.gov>; Manary,Michelle L (BPA) - TS-DITT-2 <mlmanary@bpa.gov>; Van Calcar,Pamela M (BPA) - PG-5 <pmvancalcar@bpa.gov>; Cook,Jeffrey W (BPA) - TP-DITT-2 <jwcook@bpa.gov>
Subject: RE: Order re Centralia

Thanks so much Sonya, very helpful.
Mike

From: Baskerville,Sonya L (BPA) - AI-WASH <slbaskerville@bpa.gov>
Sent: Friday, January 9, 2026 11:26 AM
To: Hairston,John L (BPA) - A-7 <jlhairston@bpa.gov>; Cooper,Suzanne B (BPA) - K-7 <sbcooper@bpa.gov>; Miller,Mike P (BPA) - T-DITT-2 <mpmiller@bpa.gov>; Chong Tim,Marcus H (BPA) - L-7 <mhchongtim@bpa.gov>; Scruggs,Joel L (BPA) - NK-7 <jlscruggs@bpa.gov>; Wingert,Kevin M (BPA) - NKP-7 <kwingert@bpa.gov>
Cc: Bustamante,Richard (BPA) - TO-DITT-2 <rxbustamante@bpa.gov>; Manary,Michelle L (BPA) - TS-DITT-2 <mlmanary@bpa.gov>; Van Calcar,Pamela M (BPA) - PG-5 <pmvancalcar@bpa.gov>; Cook,Jeffrey W (BPA) - TP-DITT-2 <jwcook@bpa.gov>
Subject: FW: Order re Centralia

Hey there. We had a good, clarifying call with DOE on the order. As some of us thought, DOE believed that Centralia was in our BA and that was the basis for the inclusion. We clarified that Centralia is not in our BA.

So, the EO doesn't pertain to BPA, and we are business as usual with TransAlta (their existing transmission service).

I think we could have a statement that says something like, "BPA's role related to the EO is business as usual as BPA provides transmission services to TransAlta. BPA does not provide power services for Centralia as Centralia is not within BPA's BA."

Curiously, DOE also had an inaccurate understanding of BPA operations with respect to WAPA on another coal plant EO.

Thanks.

Sonya Baskerville
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY
Director | Intergovernmental Affairs
slbaskerville@bpa.gov | O: 202-586-5587 | C: (b) (6)

From: Ardis, Melissa <melissa.ardis@hq.doe.gov>
Sent: Friday, December 19, 2025 2:19 PM
To: Burdick, Emily <emily.burdick@hq.doe.gov>; Tatulyan, Kevin <kevin.tatulyan@hq.doe.gov>; Baskerville,Sonya L (BPA) - AI-WASH <slbaskerville@bpa.gov>
Cc: Chong Tim,Marcus H (BPA) - L-7 <mhchongtim@bpa.gov>
Subject: Re: Order re Centralia

Will do.

Melissa Ardis
Senior Advisor, Power Marketing Administrations
Office of the Under Secretary of Energy
(b) (6)

From: Baskerville,Sonya L (BPA) - AI-WASH <slbaskerville@bpa.gov>
Sent: Friday, December 19, 2025 12:14:44 PM
To: Ardis, Melissa <melissa.ardis@hq.doe.gov>; Burdick, Emily <emily.burdick@hq.doe.gov>; Tatulyan, Kevin <kevin.tatulyan@hq.doe.gov>
Cc: Chong Tim, Marcus <mhchongtim@bpa.gov>
Subject: RE: Order re Centralia

Also, please include Jeff Cook, jwcook@bpa.gov . I forgot him. Thanks!

Sonya Baskerville
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY
Director | Intergovernmental Affairs
slbaskerville@bpa.gov | O: 202-586-5587 | C: (b) (6)

From: Baskerville,Sonya L (BPA) - AI-WASH <slbaskerville@bpa.gov>
Sent: Thursday, December 18, 2025 12:50 PM
To: Ardis, Melissa <melissa.ardis@hq.doe.gov>; Burdick, Emily <emily.burdick@hq.doe.gov>; Tatulyan, Kevin <kevin.tatulyan@hq.doe.gov>
Cc: Chong Tim,Marcus H (BPA) - L-7 <mhchongtim@bpa.gov>
Subject: RE: Order re Centralia

For BPA, me, Marcus, Rachel Dibble (rldibble@bpa.gov), Pam Van Calcar (pmvancalcar@bpa.gov), and Michelle Manary (mlmanary@bpa.gov). Thanks.

Sonya Baskerville
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY
Director | Intergovernmental Affairs
slbaskerville@bpa.gov | O: 202-586-5587 | C: (b) (6) [redacted]

From: Ardis, Melissa <melissa.ardis@hq.doe.gov>
Sent: Wednesday, December 17, 2025 10:25 AM
To: Baskerville,Sonya L (BPA) - AI-WASH <slbaskerville@bpa.gov>; Burdick, Emily <emily.burdick@hq.doe.gov>; Tatulyan, Kevin <kevin.tatulyan@hq.doe.gov>
Cc: Chong Tim,Marcus H (BPA) - L-7 <mhchongtim@bpa.gov>
Subject: RE: Order re Centralia

Hi Sonya – Thanks and agreed on a briefing being needed. Who should I include from your side in that meeting? I'll work on the right folks from our side.

Thank you,

Melissa Ardis
Senior Advisor, Power Marketing Administrations
Office of the Under Secretary of Energy
(b) (6) [redacted]
www.energy.gov

From: Baskerville,Sonya L (BPA) - AI-WASH <slbaskerville@bpa.gov>
Sent: Wednesday, December 17, 2025 8:03 AM
To: Burdick, Emily <emily.burdick@hq.doe.gov>; Tatulyan, Kevin <kevin.tatulyan@hq.doe.gov>
Cc: Ardis, Melissa <melissa.ardis@hq.doe.gov>; Chong Tim, Marcus <mhchongtim@bpa.gov>
Subject: Order re Centralia
Importance: High

Hello, all. BPA has become aware of the attached order related to Centralia, and had been aware that TransAlta and PSE have plans to restart Unit 2 to run on natural gas.

It would be good to have a briefing from DOE to ensure we have a common understanding of BPA's role in this order. It appears that this would be operations as usual once the plant is restarted running natural gas. (Power flowing within the BA). Because there was specific direction in the order, which would typically suggest action outside of normal operations, it's unclear whether the order is seeking something new or different? It would be good to make sure we understand the intent.

Thanks.

SONYA BASKERVILLE
BONNEVILLE POWER ADMINISTRATION
DEPARTMENT OF ENERGY
Director | Intergovernmental Affairs
slbaskerville@bpa.gov
O: 202-586-5587 | C: (b) (6)

Taylor,Jason E (BPA) - CGI-7

From: Baskerville,Sonya L (BPA) - AI-WASH
Sent: Monday, January 5, 2026 9:37 AM
To: Rasmussen,Adriana M (BPA) - AIR-WENATCHEE; Wright,Laura K (BPA) - LT-7; Kutil,Sarah M (BPA) - LT-7
Subject: RE: WA AG Requests Meeting

We have not had any conversations on this, and do not have any information. They should go to DOE for any information on this. Thanks.

Sonya Baskerville
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY
Director | Intergovernmental Affairs
slbaskerville@bpa.gov | O: 202-586-5587 | C: (b) (6)

From: Rasmussen,Adriana M (BPA) - AIR-WENATCHEE <amrasmussen@bpa.gov>
Sent: Monday, January 5, 2026 9:35 AM
To: Baskerville,Sonya L (BPA) - AI-WASH <slbaskerville@bpa.gov>; Wright,Laura K (BPA) - LT-7 <LKWright@bpa.gov>; Kutil,Sarah M (BPA) - LT-7 <smkutil@bpa.gov>
Subject: RE: WA AG Requests Meeting

The Governor's office reached out again over the break about the Centralia EO. They heard we had had some conversations. Are we still just referring them to DOE? Will we be working on a statement or anything?

Thanks and Happy New Year!

Adriana Rasmussen
BONNEVILLE POWER ADMINISTRATION
DEPARTMENT OF ENERGY
WA Liaison | Intergovernmental Affairs | Regional Relations
amrasmussen@bpa.gov | O: 509-886-6060 | C: (b) (6)

From: Baskerville,Sonya L (BPA) - AI-WASH <slbaskerville@bpa.gov>
Sent: Friday, December 19, 2025 10:06 AM
To: Rasmussen,Adriana M (BPA) - AIR-WENATCHEE <amrasmussen@bpa.gov>; Wright,Laura K (BPA) - LT-7 <LKWright@bpa.gov>; Kutil,Sarah M (BPA) - LT-7 <smkutil@bpa.gov>
Subject: RE: WA AG Requests Meeting

They really should touch base with DOE. We do not have any of the information/analysis of the order they probably are looking for. Thanks.

Sonya Baskerville
BONNEVILLE POWER ADMINISTRATION

U.S. DEPARTMENT OF ENERGY
Director | Intergovernmental Affairs
slbaskerville@bpa.gov | O: 202-586-5587 | C: (b) (6)

From: Rasmussen,Adriana M (BPA) - AIR-WENATCHEE <amrasmussen@bpa.gov>
Sent: Friday, December 19, 2025 1:04 PM
To: Baskerville,Sonya L (BPA) - AI-WASH <slbaskerville@bpa.gov>; Wright,Laura K (BPA) - LT-7 <LKWright@bpa.gov>; Kutil,Sarah M (BPA) - LT-7 <smkutil@bpa.gov>
Subject: RE: WA AG Requests Meeting

I've let them know and they said the AG would like to hear from BPA as soon as we are able.

From: Baskerville,Sonya L (BPA) - AI-WASH <slbaskerville@bpa.gov>
Sent: Friday, December 19, 2025 9:54 AM
To: Rasmussen,Adriana M (BPA) - AIR-WENATCHEE <amrasmussen@bpa.gov>; Wright,Laura K (BPA) - LT-7 <LKWright@bpa.gov>; Kutil,Sarah M (BPA) - LT-7 <smkutil@bpa.gov>
Subject: Re: WA AG Requests Meeting

We have to respectfully decline. They should touch base with DOE. Thanks.

SONYA BASKERVILLE
BONNEVILLE POWER ADMINISTRATION
DEPARTMENT OF ENERGY
Director | Intergovernmental Affairs
slbaskerville@bpa.gov
O: 202-586-5587 | C: (b) (6)

From: Rasmussen,Adriana M (BPA) - AIR-WENATCHEE <amrasmussen@bpa.gov>
Sent: Friday, December 19, 2025 12:36:00 PM
To: Baskerville,Sonya L (BPA) - AI-WASH <slbaskerville@bpa.gov>; Wright,Laura K (BPA) - LT-7 <LKWright@bpa.gov>; Kutil,Sarah M (BPA) - LT-7 <smkutil@bpa.gov>
Subject: WA AG Requests Meeting

Hello Sonya/Laura/Sarah,

FYI, I just got a call from the Governor's office and the AG is requesting a meeting with BPA regarding the DOE order. I referred them to DOE with questions, but they want to request the meeting all the same. I was told they are meeting with CAISO in the afternoon and are looking for information about BPA's role in executing the order. Let me know how you would like me to respond.

Thanks!

Adriana Rasmussen
BONNEVILLE POWER ADMINISTRATION
DEPARTMENT OF ENERGY
WA Liaison | Intergovernmental Affairs | Regional Relations
amrasmussen@bpa.gov | O: 509-886-6060 | C: (b) (6)

From:	Wingert,Kevin M (BPA) - NKP-DITT-2
To:	Baskerville,Sonya L (BPA) - AI-WASH; Manary,Michelle L (BPA) - TS-DITT-2; Bustamante,Richard (BPA) - TO-DITT-2; Miller,Mike P (BPA) - T-DITT-2; Scruggs,Joel L (BPA) - NK-7; Hairston,John L (BPA) - A-7; Cooper,Suzanne B (BPA) - K-7; Chong Tim,Marcus H (BPA) - L-7
Cc:	Van Calcar,Pamela M (BPA) - PG-5; Cook,Jeffrey W (BPA) - TP-DITT-2
Subject:	FINAL Draft Statement on Emergency order re: Centralia Unit 2
Date:	Wednesday, January 14, 2026 3:25:10 PM

Joel,

Here is the final version of the statement that incorporates input from Ricky, Allen, Marcus and Sonya. Please feel free to share on the DOE PA call and seek approval as needed:

After a briefing with the Department of Energy relating to the emergency order, we have confirmed that there are no additional actions for BPA relating to Centralia Unit 2. While BPA provides transmission services to TransAlta, Centralia Unit 2 is not in BPA's balancing authority area.

Very Respectfully,

Kevin Wingert
BONNEVILLE POWER ADMINISTRATION
DEPARTMENT OF ENERGY
Media Relations Specialist | Communications | Media Relations
kwingert@bpa.gov | 503-230-4140

From: Baskerville,Sonya L (BPA) - AI-WASH <slbaskerville@bpa.gov>
Sent: Wednesday, January 14, 2026 9:17 AM
To: Manary,Michelle L (BPA) - TS-DITT-2 <mlmanary@bpa.gov>; Bustamante,Richard (BPA) - TO-DITT-2 <rxbustamante@bpa.gov>; Miller,Mike P (BPA) - T-DITT-2 <mpmiller@bpa.gov>; Wingert,Kevin M (BPA) - NKP-DITT-2 <kwingert@bpa.gov>; Scruggs,Joel L (BPA) - NK-7 <jlscruggs@bpa.gov>; Hairston,John L (BPA) - A-7 <jlhairston@bpa.gov>; Cooper,Suzanne B (BPA) - K-7 <sbcooper@bpa.gov>; Chong Tim,Marcus H (BPA) - L-7 <mhchongtim@bpa.gov>
Cc: Van Calcar,Pamela M (BPA) - PG-5 <pmvancalcar@bpa.gov>; Cook,Jeffrey W (BPA) - TP-DITT-2 <jwcook@bpa.gov>
Subject: Re: Order re Centralia - DRAFT STATEMENT; please review

Agree. I went back and forth on that one!

SONYA BASKERVILLE
BONNEVILLE POWER ADMINISTRATION
DEPARTMENT OF ENERGY
Director | Intergovernmental Affairs
slbaskerville@bpa.gov

EXHIBIT 119

U.S. Energy Information Administration

Skip to sub-navigation

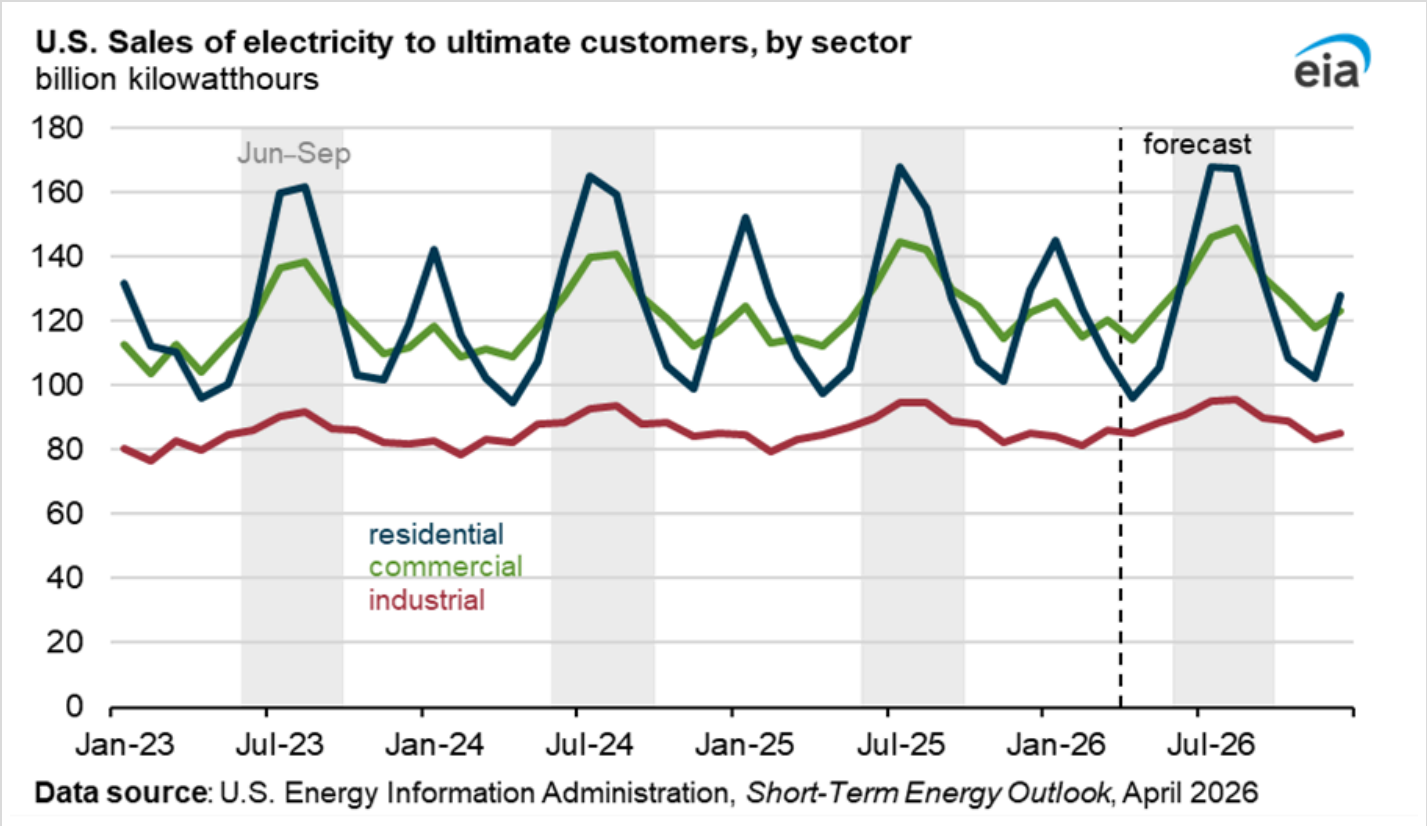
Short-Term Energy Outlook

Release Date: April 7, 2026 | **Forecast Completed:** April 6, 2026 | **Next Release Date:** May 12, 2026

Electricity, coal, and renewables

Electricity demand

Overall, we expect total electricity demand to increase by 1.2% in 2026 and reach 4,108 billion kilowatthours (BkWh). In 2027, we expect demand will increase by 3.3% and reach 4,244 BkWh.



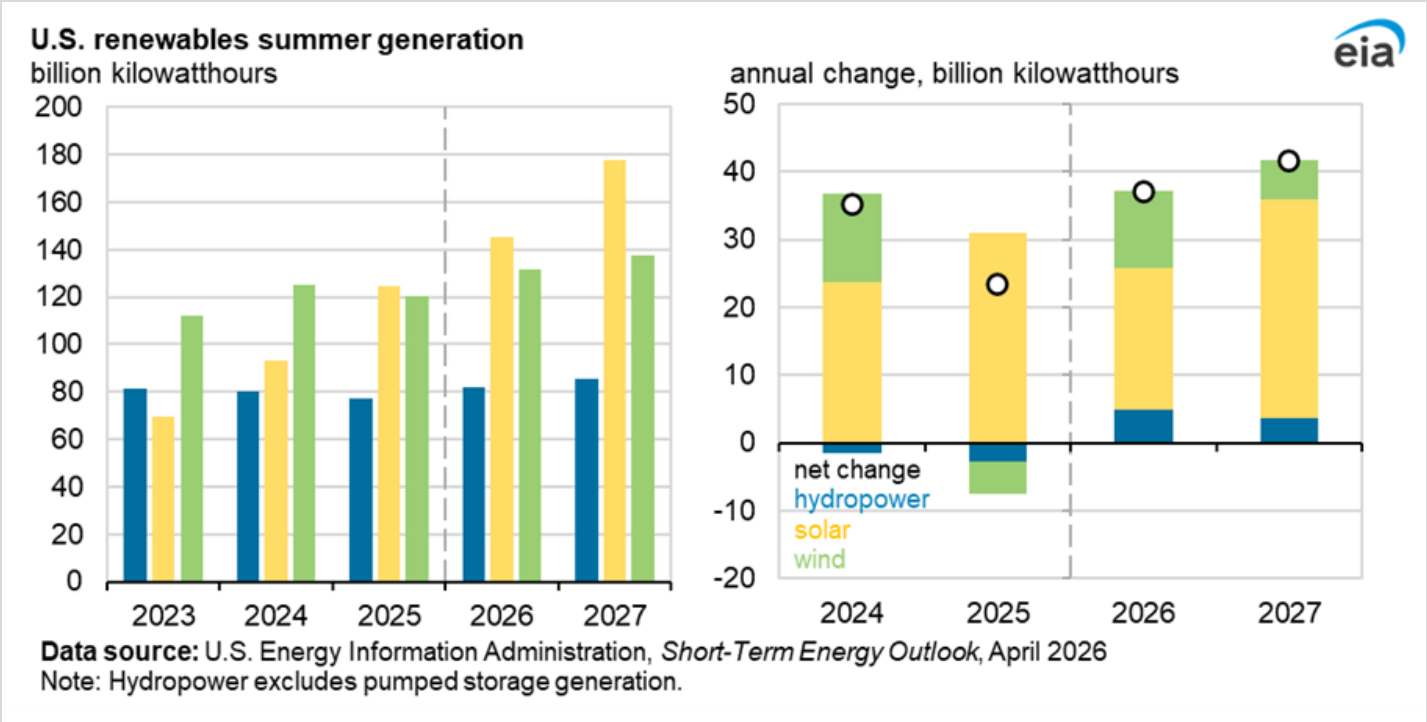
Power demand peaks in the summer months (June through September) because of increased cooling needs. We expect total demand to increase by 2.3% in the summer months this year compared with 2025 and by 3.7% in 2027. We expect the residential sector to consume the most electricity in 2026 and 2027 even as commercial demand continues to grow at a faster rate.

We expect residential demand to grow by 2.9% in the summer of 2026 and by 1.0% in 2027. Summer power demand from the commercial sector grows by 2.6% in 2026 and by 5.8% in 2027, and summer power demand from the industrial sector grows by 0.9% in 2026 and 5.1% in 2027.

Summer renewables generation

We expect total electricity generation to increase by 1.2% to 4,325 BkWh in 2026 and by 3.4% to 4,470 BkWh in 2027. Generation growth this year is led by growth from renewable sources such as solar (17%), hydro (6%), and wind (5%).

Solar generation peaks in the summer months. In the summer of 2026, we expect solar power will generate 17% more electricity than it did last summer. In 2025, solar generation in the summer months surpassed wind generation for the first time, and that trend continues in



Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, April 2026
Note: Hydropower excludes pumped storage generation.

our forecast. In the summer of 2027, we expect solar generation will grow by 22% to reach 178 BkWh, surpassing wind generation by almost 30%, although we still expect wind will generate more electricity than solar for the whole year.

We expect an increase in annual hydropower generation of 6% this year to 260 BkWh, with 6% growth in the summer months as well. A warmer than normal winter led to snow drought conditions across many western states, the area of the United States that relies most heavily on hydropower generation. However, overall precipitation in the region remained mostly near the 30-year normal over the winter months. As warmer months approach, reservoir levels particularly in the Northwest and California are mostly near capacity. This, along with other metrics, is a key factor contributing to our forecast of increasing hydro generation.

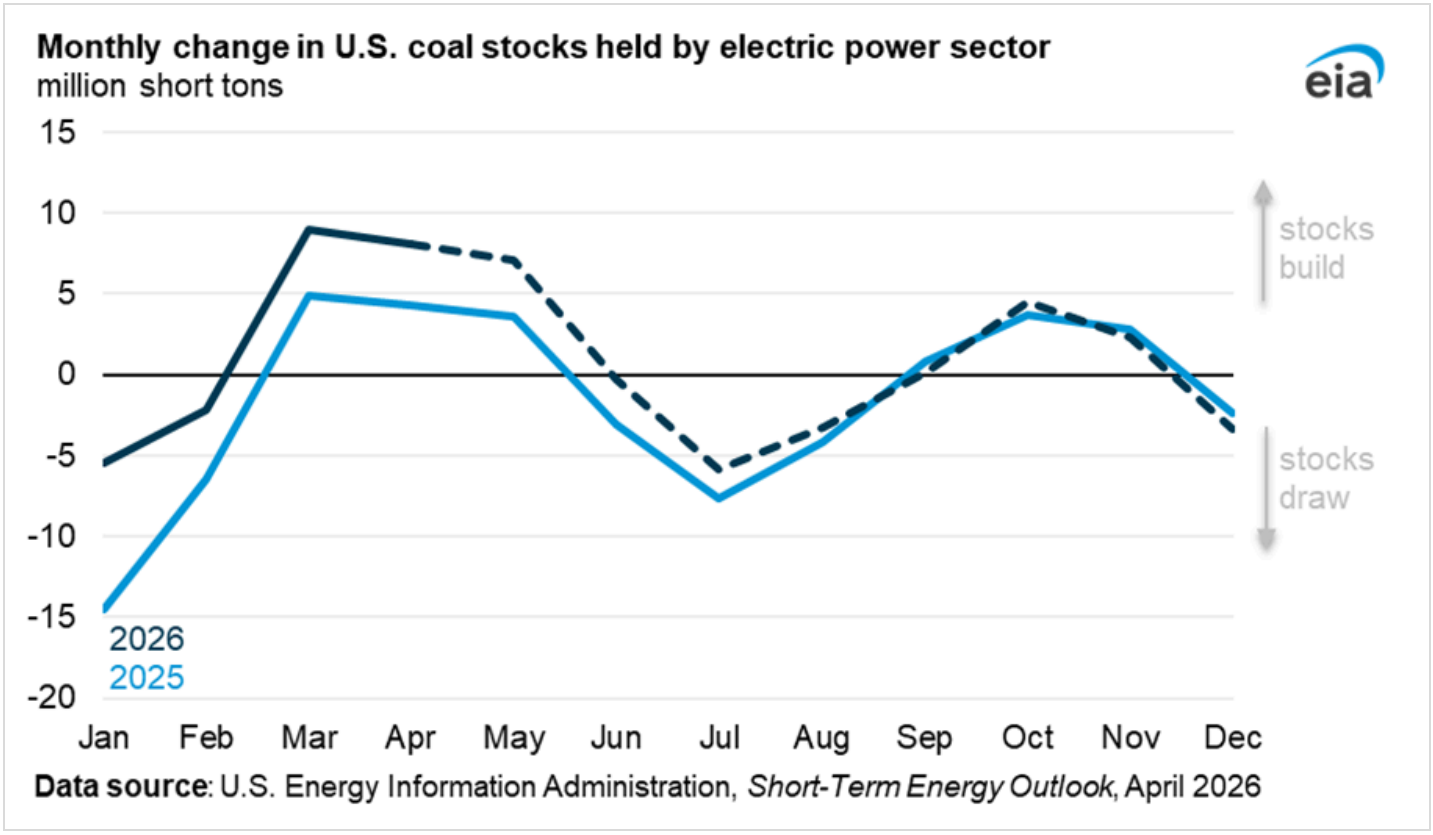
During the summer months, we expect generation from natural gas to remain flat compared with summer 2025 and generation from nuclear to increase by 2%, accounting for the planned Palisades restart.

Coal markets

Coal-fired electric power plants tend to build up their coal stocks in the spring and fall months when electricity demand is lower and plants undergo seasonal maintenance. During the first half of 2026 (1H26) we expect that U.S. electric power sector stocks will increase by an average of 3 million short tons (MMst) each month. In contrast, during 1H25 electric power sector coal stocks fell by an average of 2 MMst each month.

The main driver for the expected buildup in coal stocks during 1H26 is lower generation from coal-fired power plants. We expect the U.S. electric power sector to consume 180 MMst of coal for generation between January and June 2026, which would be 10% less than it consumed 1H25. Forecast coal production in 1H26 continues at the same pace as last year, totaling almost 260 MMst.

During 2H26, we expect a net draw of 1 MMst/month, similar to the same period in 2025. Forecast U.S. coal consumption for electricity generation in 2H26 totals 204 MMst, which is 6% lower than last year. Forecast U.S. coal production in 2H26 falls 5% year over year, similar to the consumption rate of decrease. We expect coal production to total 517 MMst for all of 2026.


Monthly change in U.S. coal stocks held by electric power sector
million short tons
eia
15
10
5
0
-5
-10
-15
-20
stocks build
stocks draw
2026
2025
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, April 2026

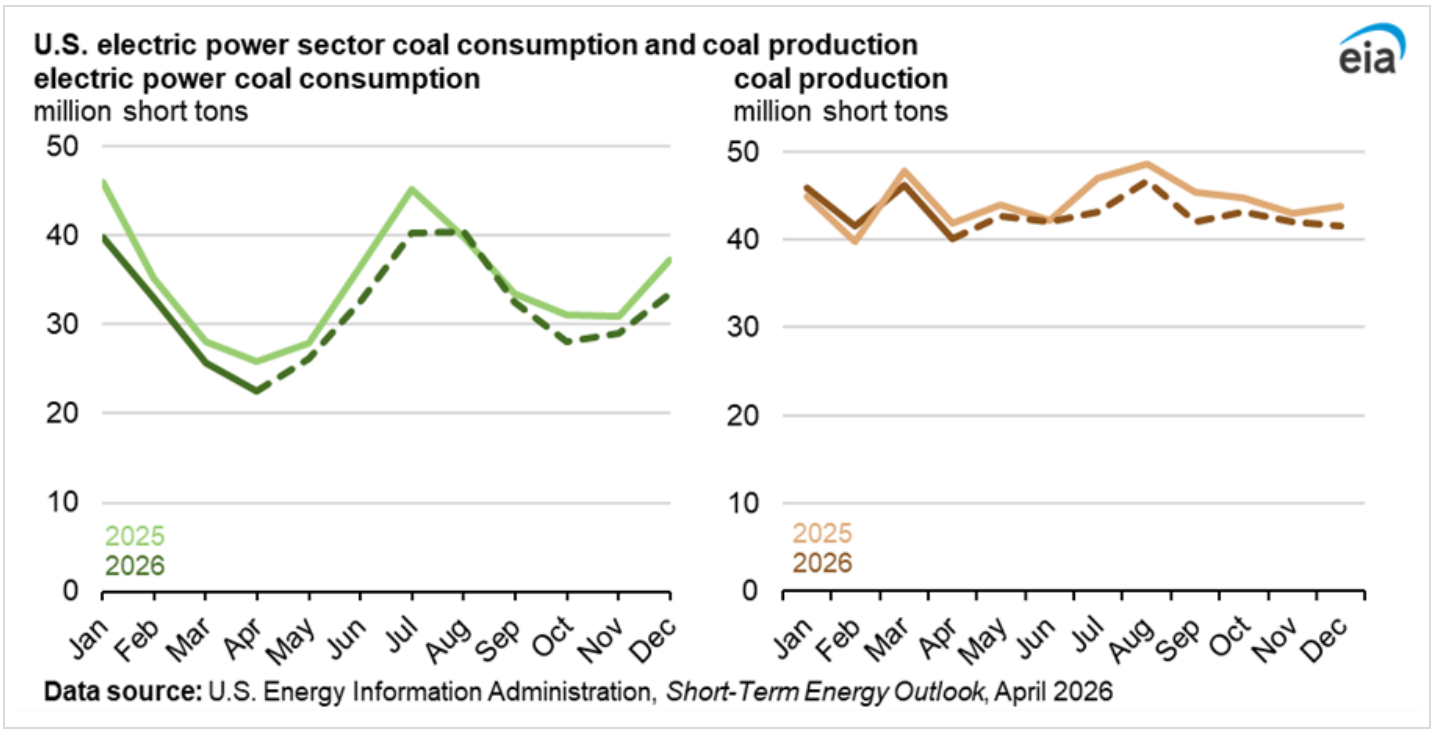

U.S. electric power sector coal consumption and coal production
electric power coal consumption
million short tons
coal production
million short tons
eia
50
40
30
20
10
0
2025
2026
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, April 2026

EXHIBIT 120

Department of Energy
Washington, DC 20585

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

Order No. 202-26-28

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

BACKGROUND

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

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

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

Order Nos. 202-25-11 and 202-25-11B, issued pursuant to FPA section 202(c), required that Centralia remain in operation for 90 days, until March 16, 2026. A subsequent order, Order No. 202-26-18, was issued pursuant to FPA section 202(c), requiring Centralia to remain in operation for 90 days, until June 14, 2026. Those orders were based on my determination that emergency conditions existed in the WECC–Northwest assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes.

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

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

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

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

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

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

[9] *See*, *e.g.*, *id.* at 1–3.

[10] *See*, *e.g.*, *id.* at 3–4.

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

[12] *Id*.

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

[14] *Id*. at 10.

[15] *Id*.

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

EMERGENCY SITUATION

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

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

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[16] *Id*. at 2.

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

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

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

[20] *Id.* at 7.

[21] *Id.* at 8.

[22] *Id.* at 19.

[23] *Id.*

NERC's 2026 Summer Reliability Assessment (2026 SRA) classifies the WECC–Northwest region as an Elevated Risk[24] area with highest-risk conditions occurring in early evening hours (around 6 p.m.) in late summer.[25] The region faces "elevated risks of electricity supply shortfalls during periods of more extreme summer conditions or [is] subject to localized constraints that raise the risk levels of certain small areas within the broader system. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar photovoltaic (PV) energy conditions."[26] Under typical outage conditions the 2026 SRA forecasts reserve margins to be 25.2% and in a scenario with extreme conditions such as higher demand, outages, and derates, reserve margin is estimated to drop to 8.8%, below the 2026 SRA Reference Margin Level of 10.0%. In normal and typical outages, reserve margins in the 2026 SRA are expected to tighten compared to the 2025 SRA, partly due to net demand growth of 4.6% compared to an increase in energy availability by generation resources of 1.5%. NERC notes that "[t]hermal generators with diverse fuel sources can be an important electricity resource, especially during winter when solar PV and battery resources are less capable compared to summer months."[27]

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

> WECC-Northwest: The coming summer brings challenging hydrological conditions for regions in which hydropower makes up half or more of the supply fleet. Almost the entire Western Interconnection is in the grips of a persistent drought or in an area where drought development has a greater likelihood through the end of July. In Washington, for example, the snow water equivalent was at 52% of normal levels as of April 1 this year when snowpack typically reaches its peak. While the total water year supply is forecast to be nearly average in the Columbia River Basin, snowpack peaked at low elevation and melted early in the year. This has implications for the expected resources available to the Northwest, the generation mix for which is 55% hydropower. The region is contending with a nearly 5% increase in net internal demand from the 2025 SRA and a nearly 2% drop in existing resources as well as a roughly 43% drop in expected Tier 1 resources. Though higher modeled net transfers are projected to contribute double what they were projected to last year (albeit with the increase largely attributable to a modeling change that accounts for economic transfers), this

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

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

[26] *Id*. at 2.

[27] *Id.* at 9.

> was not enough to prevent the drop in the Anticipated Reserve Margin from 32% last year to 27% this year.[28]
>
> Peak net internal demand is projected to grow 4.6% over last summer's forecasts; however, anticipated resources are showing just a 1.5% increase in energy availability, leading to tighter margins. Wide-area heat events, wildfires, and low snow-water equivalents due to a changing climate impact generation resource and transmission availability and remain a continued reliability concern. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads or derates, limiting energy availability. Supply chain constraints and economic uncertainty may impact Tier 1 resources. There have been instances where operators had difficulty maintaining frequency due to sudden disconnection of large loads necessitating additional regulation capability. Expected resources do not meet operating reserve requirements under the assessed extreme scenarios.[29]

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

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[28] *Id*. at 2.

[29] *Id*. at 36.

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

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

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

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

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

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

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

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

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

[36] *Id.*

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

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

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

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

ORDER

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

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

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Centralia Unit 2 shall be made available for operation through September 12, 2026.

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

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

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

[40] *Id*.

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

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

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

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

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

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

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

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

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

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

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

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

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

Chris Wright

Chris Wright
Secretary of Energy

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

Washington Utilities and Transportation Commission
Chairman Brian Rybarik
Commissioner Milt Doumit
Commissioner Ann Rendahl

EXHIBIT 121

Department of Energy
Washington, DC 20585

Order No. 202-26-22

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

BACKGROUND

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

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

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

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

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

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

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

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

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

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

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

[6] *Id.* at 1.

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

[8] *Id*.

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

[10] *Id*.

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

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

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

CONTINUING EMERGENCY CONDITIONS

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

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

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

[14] *Id.* at 12.

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

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

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

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

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

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

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

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

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

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

[21] MISO Transmittal Letter at 3.

[22] *Id.* at 3–4.

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

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

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

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

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

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

[24] *Id.* at 11.

[25] *Id.*

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

[27] *Id.* at 12.

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

[29] *Id.* at 8.

[30] *Id.* at 43.

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

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

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

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

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[31] *Id.* at 15.

[32] *Id*.

[33] *Id*.

[34] NERC, *2023–2024 Winter Reliability Assessment*, at 5 (Nov. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

[35] NERC, *2024–2025 Winter Reliability Assessment*, at 15 (Nov. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

[36] MISO 2025–2026 Planning Resource Auction at 13.

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

[38] *Id.* at 2.

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

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

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

[39] *Id.* at 7.

[40] *Id.* at 9.

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

[42] *Id*.

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

[44] *Id.* P 84.

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

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

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

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

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

[47] *Id*.

[48] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

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

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

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

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

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

ORDER

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

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

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

[53] *Id.* at 6

[54] *Id.* at 7.

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

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

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

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

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

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

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

[56] 16 U.S.C. § 824a(c)(4).

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

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

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

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

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

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

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

Chris Wright

Chris Wright
Secretary of Energy
cc:

FERC Commissioners

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

Michigan Public Service Commissioners

Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

EXHIBIT 122

Department of Energy
Washington, DC 20585

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

Order No. 202-26-24

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

BACKGROUND

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

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

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

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

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

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

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

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

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

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

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

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

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

CONTINUING EMERGENCY CONDITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[26] *Id*.

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

[28] *Id*.

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

[30] *Id*.

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

[32] *Id.* at 14.

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

[34] Bielak Aff. at 10.

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

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

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

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

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[35] *Id.*at 12.

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

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

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

[39] *Id.* at 8.

[40] *Id.* at 16.

[41] *Id.* at 91.

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

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

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

[43] *Id*.

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

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

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

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

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

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

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

ORDER

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

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

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

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

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

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

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

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

C. All operations of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with

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

[55] 16 U.S.C. § 824a(c)(4).

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

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

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

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

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

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

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



Chris Wright
Secretary of Energy

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

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

EXHIBIT 123

Department of Energy
Washington, DC 20585

Order No. 202-25-14

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

BACKGROUND

Craig Station (Craig) is an electric generating facility in Craig, Colorado. Craig is operated by the Tri-State Generation and Transmission Association (Tri-State). Craig consists of three coal-fired generation units, Unit 1 (446.4 MW), Unit 2 (446.4 MW), and Unit 3 (534.8 MW), with a combined name plate capacity of 1427.6 MW.[3] Unit 1 and Unit 2 are co-owned by Tri-State, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy (co-owners).[4] Unit 3 is wholly owned by Tri-State. Unit 1 and Unit 2 began operations in 1980 and 1979 respectively. Unit 3 began operations in 1984. Unit 1 is slated to cease operations in December 2025. Unit 2 and Unit 3 are slated to retire in 2028.[5]

EMERGENCY SITUATION

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that in the WECC Northwest assessment area, which includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming, "[e]nergy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio." The LTRA notes that:

> [f]ive [gigawatts] of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar, wind, and [battery energy storage systems], further increasing variability in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of [battery energy storage systems] resources are a concern as they assist in meeting demand

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] U.S. Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024), https://www.eia.gov/electricity/data/eia860/.
[4] Platte River Power Authority, Craig Units 1 & 2 (Yampa Project), https://prpa.org/generation/yampa-project/.
[5] As a coal-fired facility, it would be difficult for the Craig Unit 1 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Tri-State and co-owners were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

during shoulder periods where solar availability is dropping but loads remain high.[6]

The 2024 WECC Western Assessment of Resource Adequacy notes that peak demand in WECC's Northwest-Central subregion, which includes Colorado, is "forecast to grow by 8.5% over the next decade, from 33 GW in 2025 to 36 GW in 2034."[7] Meanwhile, WECC notes that most planned retirements are "baseload generation, such as coal, natural gas, and nuclear."[8]

Since 2019, 571.3 MW of coal-fired generating capacity across six units at three locations have retired in Colorado,[9] leading to a decline in the share of coal-generated electricity from 45% to 28%.[10] Looking forward, by 2029, about 3,700 megawatts of coal-fired generating capacity in Colorado is scheduled to retire according to the Energy Information Administration (EIA),[11] accounting for all but one coal-fired power plant in Colorado. In that same time frame, 675.6 MW of natural gas-fired generating capacity in Colorado will retire as well.[12] In 2025, intermittent wind accounted for over 5,300 MW of Colorado's electricity generating capacity.[13]

Executive orders issued by President Donald J. Trump on January 20, 2025 and April 8, 2025 underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[14] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[15] In a subsequent Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion

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[6] *NERC 2024 Long-Term Reliability* Assessment, at 130 (Dec. 2024, corrected Jul. 11, 2025), https://www.nerc.com/globalassets/ourwork/assessments/2024-ltra_corrected_july_2025.pdf.

[7] Western Electricity Coordinating Council, *Western Assessment of Resource Adequacy 2024: Peak Demand by Subregion*, at 2, https://www.wecc.org/sites/default/files/documents/products/2024/WARA%202024%20Peak%20Demand%20by%20Subregion.pdf.

[8] Western Electricity Coordinating Council, *Western Assessment of Resource Adequacy*, https://feature.wecc.org/waraa/.

[9] *Id.*

[10] U.S. Energy Information Administration, *Electricity Data Browser, Net Generation for All Sectors Annually from 2019-2024, State: Colorado, (last accessed Dec. 30, 2025),* https://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vtvp&geo=0000000000g&sec=g&freq=A&start=2019&end=2024&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0.

[11] U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of November 2025, Plant State: Colorado, Technology: Conventional Steam Coal* (Nov. 2025), https://www.eia.gov/electricity/data/eia860m/.

[12] U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of November 2025, Plant State: Colorado, Technology: Natural Gas Fired Combustion Turbine and Natural Gas Stream Turbine* (Nov. 2025), https://www.eia.gov/electricity/data/eia860m/.

[13] U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of November 2025, Plant State: Colorado, Technology: Onshore Wind Turbine* (Nov. 2025), https://www.eia.gov/electricity/data/eia860m/.

[14] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[15] *Id.*

of artificial intelligence data centers and increase in domestic manufacturing."[16]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[17]

ORDER

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

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

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

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

A. From December 30, 2025, Tri-State and the co-owners, shall take all measures necessary to ensure that Craig Unit 1 is available to operate at the direction of either Western Area Power Administration (WAPA)—Rocky Mountain Region Western Area Colorado Missouri (WACM) in its role as Balancing Authority or the Southwest Power Pool (SPP) West in its role as the Reliability Coordinator, as applicable.[19] Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry

[16] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[17] U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (Jul. 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

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

[19] U.S. Energy Information Administration, Form EIA-860, Schedule 3: Plant Data (2024), https://www.eia.gov/electricity/data/eia860/.

practices.

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

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

D. By January 20, 2026, Tri-State, in coordination with the co-owners, is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Craig Unit 1 consistent with this Order. Tri-State and the co-owners shall also provide such additional information regarding the environmental and operational impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Tri-state and the co-owners are directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

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

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

H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 30, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 30, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 7:08PM EST on this 30th day of December 2025.

Chris Wright

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**

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

Colorado Public Utilities Commission

Chairman Eric Blank
Commissioner Megan Gilman
Commissioner Tom Plant

EXHIBIT 124

Department of Energy
Washington, DC 20585

Order No. 202-26-21

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

BACKGROUND

Craig Station (Craig) is an electric generating facility in Craig, Colorado. Craig is operated by the Tri-State Generation and Transmission Association (Tri-State). Craig consists of three coal-fired generation units, Unit 1 (446.4 MW), Unit 2 (446.4 MW), and Unit 3 (534.8 MW), with a combined name plate capacity of 1427.6 MW.[4] Unit 1 and Unit 2 are co-owned by Tri-State, Platte River Power Authority, Salt River Project, PacifiCorp, and Public Service Company of Colorado (a subsidiary of Xcel Energy), hereinafter collectively referred to as the "co-owners".[5] Unit 3 is wholly owned by Tri-State. Unit 1 and Unit 2 began operations in 1980 and 1979 respectively. Unit 3 began operations in 1984. Unit 1 was slated to cease operations in December 2025. Unit 2 and Unit 3 are slated to retire in 2028.[6]

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[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] The 2024 Long-Term Reliability Assessment (LTRA) from the North American Electric Reliability Corporation (NERC) included Colorado in the WECC Northwest assessment area. The 2025 LTRA provides new assessment area boundaries for WECC to provide more geographic detail of reliability risk information and to, "reflect a more accurate alignment with operational and planning realities, as well as the footprints of various entities." In the 2025 LTRA, Colorado is included in the WECC Rocky Mountain assessment region.

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

[5] Platte River Power Authority, Craig Units 1 & 2 (Yampa Project), https://prpa.org/generation/yampa-project/.

[6] As a coal-fired facility, it would be difficult for the Craig Unit 1 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair if a unit comes offline. In addition, other practical issues, such as

Order No. 202-25-14, issued pursuant to FPA section 202(c) on December 30, 2025, required that Tri-State and the co-owners take all measures necessary to ensure that Craig Unit 1 continues to be available to operate for 90 days, until March 30, 2026. This order was based on my determination that emergency conditions existed within the WECC Northwest assessment area.

Specifically, I determined that the WECC Northwest assessment area faced significant amount of retiring baseload generation resources and concerns meeting demand during shoulder periods.[7] I determined that the continued availability of Craig Unit 1 would provide additional generation capacity, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.[8] I determined that the continued availability of Craig Unit 1 was necessary to alleviate immediate and anticipated threats to reliability.[9] My determination was based on several facts.

First, in its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that in the WECC Northwest assessment area, which included Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming, "[e]nergy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio." The 2024 LTRA notes that:

> [f]ive [gigawatts] of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar, wind, and [battery energy storage systems], further increasing variability in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of [battery energy storage systems] resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high.[10]

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employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Tri-State and co-owners were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

[7] *See*, *e.g.*, *Tri-State Generation and Transmission Association (Tri-State), Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy,* Order No. 202-25-14, at 1–2 (Dec. 30, 2025).

[8] *See, e.g.*, *id.* at 1–3.

[9] *See, e.g.*, *id.* at 3.

[10] NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024, corrected Jul. 11, 2025), at 130 (Dec. 2024, corrected Jul. 11, 2025), https://www.nerc.com/globalassets/ourwork/assessments/2024-ltra_corrected_july_2025.pdf .

Second, the 2024 WECC Western Assessment of Resource Adequacy notes that peak demand in WECC's Northwest-Central subregion, which included Colorado at the time, is "forecast to grow by 8.5% over the next decade, from 33 GW in 2025 to 36 GW in 2034."[11] Meanwhile, WECC notes that most planned retirements are "baseload generation, such as coal, natural gas, and nuclear."[12]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order No. 202-25-14 continue, both in the near and long term.[13] The availability of electricity from Craig Unit 1 will continue to be critical to maintain reliability in the WECC Rocky Mountain assessment area.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.[14] While NERC assessed that the WECC Rocky Mountain region, which includes Colorado, is at normal risk of energy shortfalls over the next five years,[15] the area has an "[anticipated reserve margin] that falls below the [Reference Margin Level] in Summer 2034 and 2035, and Winter 2034–35."[16] The LTRA also notes that the WECC-Rocky Mountain assessment area faces challenges from an aging thermal resource fleet, which can lead to unplanned outages, exacerbated by supply chain issues, and vendor availability.[17] Additionally, both solar and wind variability are year-round concerns, and while the region is pursuing advancement into Regional Transmission Organizations (RTOs) to leverage a wider footprint, smaller entities currently have limited geographic diversity to counteract these generation constraints.[18]

The 2025 WECC Western Assessment of Resource Adequacy notes that "the West's planned resource buildout will not keep up with anticipated load growth over the next decade, particularly in the Basin and Northwest subregions. The West could see

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[11] WECC, *Western Assessment of Resource Adequacy 2024: Peak Demand by Subregion*, at 2, https://www.wecc.org/sites/default/files/documents/products/2024/WARA% 202024%20Peak%20Demand%20by%20Subregion.pdf.

[12] WECC, Western Assessment of Resource Adequacy, https://feature.wecc.org/wara/.

[13] Further, as noted in Order No. 202-25-14, as a coal-fired facility, it would be difficult for Craig Unit 1 to resume operations once it has been retired. *See* Order No. 202-25-14 at 1.

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

[15] *Id.* at 7.

[16] *Id.* at 160.

[17] *Id.* at 161.

[18] *Id.*

energy shortfalls as early as 2028."[19] The assessment goes on to say that "[i]f resources are added as planned, loss of load may be limited to the Basin and Northwest subregions. However, if planned resource additions are delayed or cancelled, other subregions could also be at risk."[20] Further, the assessment highlights that 90% of planned resources over the next decade are inverter-based resources, which "continue the rapid evolution of the resource mix away from traditional dispatchable resources to more weather-dependent resources."[21]

Since 2019, the retirement of coal-fired generating capacity in Colorado has led to a decline in the share of coal-generated electricity from 45% to 25%.[22] Looking forward, by 2029, about 3,700 megawatts (MW) of coal-fired generating capacity in Colorado is scheduled to retire according to the Energy Information Administration (EIA),[23] accounting for all but one coal-fired power plant in Colorado. In that same time frame, 620 MW of natural gas-fired generating capacity in Colorado will retire as well.[24] In 2025, intermittent wind accounted for over 5,300 MW of Colorado's electricity generating capacity.[25] Additionally, Colorado Public Utilities Commissioners

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[19] WECC, *Western Assessment of Resource Adequacy*, https://feature.wecc.org/2025wara/index.html.

[20] *Id.*

[21] *Id.*

[22] U.S. Energy Information Administration, *Electricity Data Browser, Net Generation for All Sectors Annually from 2019-2025, State: Colorado, (last accessed Mar. 18, 2026),* https://www.eia.gov/electricity/data/browser/#/topic/0? agg=2,0,1&fuel=vtvp&geo=0000000000g&sec=g&freq=A&start=2019&end=2024&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0.

[23] U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of January 2026, Plant State: Colorado, Technology: Conventional Steam Coal* (Jan. 2026), https://www.eia.gov/electricity/data/eia860m/.

[24] U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of January 2026, Plant State: Colorado, Technology: Natural Gas Fired Combustion Turbine and Natural Gas Stream Turbine* (Jan. 2026), https://www.eia.gov/electricity/data/eia860m/.

[25] U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of January 2026, Plant State: Colorado, Technology: Onshore Wind Turbine* (Jan. 2026), https://www.eia.gov/electricity/data/eia860m/.

have expressed concerns about the ability of certain utilities to meet projected summer 2026 loads.[26]

Order No. 202-25-14 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[27] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[28] In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[29]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[30] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth.

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[26] RTO Insider, *Comanche 3 Repair Delay Raises RA Concerns in Colorado*, (March 26, 2026), https://www.rtoinsider.com/129021-comanche-3-repair-delay-raises-ra-concerns-in-colorado/.

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

[28] *Id*.

[29] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[30] U.S. Dep't of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

ORDER

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

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

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Craig Unit 1 shall be made available for operation through June 28, 2026.

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

A. For March 31, 2026, Tri-State and the co-owners, shall take all measures necessary to ensure that Craig Unit 1 is available to operate at the direction of either Western Area Power Administration (WAPA)—Rocky Mountain Region, Western Area Colorado Missouri (WACM), in its role as Balancing Authority,[32] or the Southwest Power Pool (SPP) West in its role as the Reliability Coordinator,[33] as applicable.

B. From April 1, 2026, SPP, Tri-State and the co-owners shall take all measures

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

[32] *See* EIA-930A 2024 Data, https://www.eia.gov/electricity/gridmonitor/about. On EIA-930A 2024 SCH 2, the balancing authority (BA) Code for Craig is WACM. *See* EIA-930 data reference tables, https://www.eia.gov/electricity/gridmonitor/about. On EIA-930 data reference tables BA Code WACM is associated with Western Area Power Administration—Rocky Mountain Region.

[33] SPP, *Western RC Services,* https://www.spp.org/western-services/western-rc-services/#:~:text=SPP%20is%20a%20certified%20Reliability%20Coordinator%20(RC),Interchange%20Tool%20*%20Western%20Interconnection%20Synchrophasor%20Project.

necessary to ensure that Craig Unit 1 is available to operate.[34] For the duration of this Order, SPP is directed to take every step to employ economic dispatch of Craig Unit 1 to minimize costs to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Tri-State and the co-owners are directed to comply with all orders from SPP related to the availability and dispatch of Craig Unit 1.

C. To minimize adverse environmental impacts, this Order limits operation of Craig Unit 1 to the times and within the parameters established in paragraph A and paragraph B. SPP and Tri-State shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Craig Unit 1 has operated in compliance with this Order.

D. All operations of Craig Unit 1 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.

E. By April 14, 2026, SPP and Tri-State, in coordination with the co-owners, are directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures each has taken and is planning to take to ensure the operational availability of Craig Unit 1 consistent with this Order. SPP, Tri-State and the co-owners shall also provide such additional information regarding the environmental and operational impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

F. Tri-state and the co-owners are directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

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

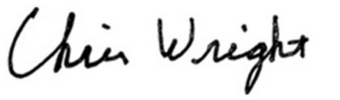
H. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Craig Unit 1 shall not be considered a capacity resource.

I. This Order shall be effective from March 31, 2026 through June 28, 2026, with the exception of applicable compliance obligations in paragraph E.

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[34] WAPA, *Southwest Power Pool RTO Membership Initiative,* https://www.wapa.gov/about-wapa/the-source/key-topics/southwest-power-pool-membership/#:~:text=Since%202020%2C%20WAPA's%20Colorado%20River,FERC%20website%20under%20Docket%20No.

Issued in Washington, D.C. on this 30th day of March 2026.



Chris Wright
Secretary of Energy

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

Colorado Public Utilities Commission
Chairman Eric Blank
Commissioner Megan Gilman
Commissioner Tom Plant

EXHIBIT 125

Department of Energy
Washington, DC 20585

Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Public Service Company of Colorado, and Southwest Power Pool
Regarding Craig Station

Order No. 202-26-31

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

BACKGROUND

Craig Station (Craig) is an electric generating facility in Craig, Colorado. Craig is operated by the Tri-State Generation and Transmission Association (Tri-State). Craig consists of three coal-fired generation units, Unit 1 (446.4 MW), Unit 2 (446.4 MW), and Unit 3 (534.8 MW), with a combined name plate capacity of 1427.6 MW.[4] Unit 1 and Unit 2 are co-owned by Tri-State, Platte River Power Authority, Salt River Project, PacifiCorp, and Public Service Company of Colorado (a subsidiary of Xcel Energy), hereinafter collectively referred to as the co-owners.[5] Unit 3 is wholly owned by Tri-State. Unit 1 and Unit 2 began operations in 1980 and 1979, respectively. Unit 3 began operations in 1984. Unit 1 was slated to cease operations in December 2025. Unit 2 and Unit 3 are slated to retire in 2028.[6]

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[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] The 2024 Long-Term Reliability Assessment (LTRA) from the North American Electric Reliability Corporation (NERC) included Colorado in the WECC–Northwest assessment area. The 2025 LTRA provides new assessment area boundaries for WECC to provide more geographic detail of reliability risk information and to, "reflect a more accurate alignment with operational and planning realities, as well as the footprints of various entities." In the 2025 LTRA, Colorado is included in the WECC–Rocky Mountain assessment region.

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

[5] Platte River Power Authority, Craig Units 1 & 2 (Yampa Project), https://prpa.org/generation/yampa-project/.

[6] It likely would be difficult for the coal-fired unit to resume operations once retired. Specifically, practical issues, such as acquiring employment, contracts, and

Order Nos. 202-25-14 and 202-26-21, issued pursuant to FPA section 202(c) on December 30, 2025, and March 30, 2026, respectively, each required that Craig Unit 1 continue to be available to operate for 90 days, until March 30, 2026, and June 28, 2026, respectively. Those orders were based on my determination that emergency conditions existed within the WECC–Northwest and WECC–Rocky Mountain assessment areas.

Specifically, I determined that the WECC–Northwest and, later, WECC–Rocky Mountain, assessment areas faced significant amount of retiring baseload generation resources and concerns meeting demand during shoulder periods.[7] I determined that the continued operation of Craig Unit 1 would provide additional generation capacity, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.[8] I determined that the continued operation of Craig Unit 1 was necessary to alleviate immediate and anticipated threats to reliability.[9]

My determination was based on several facts. First, in its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that in the WECC–Northwest assessment area, which included Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming, "[e]nergy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio." The 2024 LTRA notes that:

> Five [gigawatts (GW)] of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar, wind, and [battery energy storage systems], further increasing variability in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of [battery energy storage systems]

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permits, may greatly increase the timeline for resumption of operations, such that the facility may not be available in the period needed. Moreover, if the co-owners were to begin disassembling the unit or other related facilities, the associated challenges would be greatly exacerbated. The costs and time of decommissioning a coal plant are extensive, and restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Jennifer Lessick et al., *Bus. Models for Coal Plant Decommissioning*, at 9–12 (Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

[7] *See*, *e.g.*, *Tri-State Generation & Transmission Ass'n*, DOE Order No. 202-25-14, at 1–2 (Dec. 30, 2025) (*Tri-State*).

[8] *See id.* at 1–3.

[9] *See id.* at 3.

resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high.[10]

Second, the 2024 WECC Western Assessment of Resource Adequacy notes that peak demand in WECC's Northwest-Central subregion, which included Colorado at the time, is "forecast to grow by 8.5% over the next decade, from 33 GW in 2025 to 36 GW in 2034."[11] Meanwhile, WECC notes that most planned retirements are "baseload generation, such as coal, natural gas, and nuclear."[12]

Further, in January 2026, NERC released its 2025 Long-Term Reliability Assessment.[13] While NERC assessed that the WECC–Rocky Mountain region, which includes Colorado, is at normal risk of energy shortfalls over the next five years,[14] the area has an "[anticipated reserve margin] that falls below the [Reference Margin Level] in Summer 2034 and 2035, and Winter 2034–35."[15] The LTRA also notes that the WECC–Rocky Mountain assessment area faces challenges from an aging thermal resource fleet, which can lead to unplanned outages, exacerbated by supply chain issues, and vendor availability.[16] Additionally, both solar and wind variability are year-round concerns, and while the region is pursuing advancement into Regional Transmission Organizations (RTO) to leverage a wider footprint, smaller entities currently have limited geographic diversity to counteract these generation constraints.[17]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-14 and 202-26-21 continue, both in the near and long term.[18] The production of electricity from Craig Unit 1 continues to be critical to maintain reliability in the WECC–Rocky Mountain assessment area.

The 2025 WECC Western Assessment of Resource Adequacy notes that "the West's planned resource buildout will not keep up with anticipated load growth over the

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

[11] WECC, *W. Assessment of Res. Adequacy 2024: Peak Demand by Subregion*, at 2, https://www.wecc.org/wecc-document/17066.

[12] WECC, *W. Assessment of Res. Adequacy 2024* , https://feature.wecc.org/wara/.

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

[14] *See id.* at 7.

[15] *Id.* at 160–61.

[16] *See id.* at 161.

[17] *Id.*

[18] Further, as noted in *Tri-State*, as a coal-fired facility, it would be difficult for Craig Unit 1 to resume operations once it has been retired. *See Tri-State*, DOE Order No. 202-25-14 at 1.

next decade, particularly in the Basin and Northwest subregions. The West could see energy shortfalls as early as 2028."[19] The assessment goes on to say that "[i]f resources are added as planned, loss of load may be limited to the Basin and Northwest subregions. However, if planned resource additions are delayed or cancelled, other subregions could also be at risk."[20] Further, the assessment highlights that 90% of planned resources over the next decade are inverter-based resources, which "continue the rapid evolution of the resource mix away from traditional dispatchable resources to more weather-dependent resources."[21] The assessment notes that "entities plan to retire 22 GW of generation over the next 10 years. The vast majority is baseload generation such as coal (7 GW), natural gas (8 GW), and nuclear (2.3 GW, Diablo Canyon's two units, in 2029 and 2030)."[22]

Between 2019 and 2024, the retirement of coal-fired generating capacity in Colorado has led to a decline in the share of coal-generated electricity from 45% to 25%.[23] Looking forward, by 2029, about 3,700 megawatts (MW) of coal-fired generating capacity in Colorado is scheduled to retire according to the Energy Information Administration,[24] accounting for all but one coal-fired power plant in Colorado. In that same time frame, 620 MW of natural gas-fired generating capacity in Colorado will retire as well.[25] In 2025, intermittent wind accounted for over 5,300 MW of Colorado's electricity generating capacity.[26] Additionally, Colorado Public Utilities Commissioners have expressed concerns about the ability of certain utilities to meet projected summer 2026 loads.[27]

Finally, in May 2026, NERC released its 2026 Summer Reliability Assessment. According to NERC, Anticipated Reserve Margins will remain above the Reference Margin Level, they note that "wildfires in the region, along with extreme heat conditions

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

[20] *Id.*

[21] *Id.*

[22] *Id.*

[23] U.S. Energy Info. Admin. (EIA), *Elec. Data Browser, Net Generation for All Sectors Annually from 2019-2025, State: Colorado*, https://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vtvp&geo=0000000000g&sec=g&freq=A&start=2019&end=2024&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0.

[24] EIA, *Preliminary Monthly Elec. Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)* (Jan. 2026), https://www.eia.gov/electricity/data/eia860m/ (choose "January 2026" XLS document under "2026" column, titled "Inventory of Operating Generators as of Jan. 2026").

[25] *Id.*

[26] *Id.*

[27] *Comanche 3 Repair Delay Raises RA Concerns in Colo.*, RTO INSIDER (Mar. 26, 2026), https://www.rtoinsider.com/129021-comanche-3-repair-delay-raises-ra-concerns-in-colorado/.

for the summer, pose the greatest reliability risk scenario for the Rocky Mountains . . . [which] can impact rural communities disproportionately."[28]

Order Nos. 202-25-14 and 202-26-21 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[29] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[30] In the subsequent Executive Order No. 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[31]

In addition, President Trump issued a White House Memo for the Secretary of Energy that emphasized the findings of Executive Order No. 14156, stating that "ensuring reliable coal supply chains and baseload power generation capacity is essential to the United States national defense… Without sufficient coal-fired baseload power, the United States will lack the stable electricity required to support defense installations, industrial expansion, and the high-energy demands of emerging technologies, such as artificial intelligence."[32] The President "further determine[d] that action to expand coal supply chain capacity and baseload generation availability is necessary to avert an

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[28] NERC, *2026 Summer Reliability Assessment*, at 37, https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

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

[30] *Id*.

[31] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/ (*Strengthening the Reliability and Security of the United States Electric Grid*).

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

industrial resource or critical technology item shortfall that would severely impair national defense capability."[33]

Further, the Department of Energy detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order No. 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[34]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[35] This statutory language constitutes a specific grant of authority to the Secretary to require the operation of Craig Unit 1 when the Secretary has determined that such operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity, or a shortage of electric energy or facilities for generation or transmission of electric energy.

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

I have determined that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Craig Unit 1 shall be made available for operation through September 26, 2026.

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[33] *Id.*

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

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

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

A. From June 29, 2026, at the direction of the Southwest Power Pool (SPP) in its role as Balancing Authority and Reliability Coordinator, Tri-State and the co-owners shall take all measures necessary to ensure that Craig Unit 1 is available to operate. For the duration of this Order, SPP is directed to take every step to employ economic dispatch of Craig Unit 1 to minimize costs to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Tri-State and the co-owners are directed to comply with all orders from SPP related to the availability and dispatch of Craig Unit 1.

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

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

D. By July 14, 2026, Tri-State, in coordination with the co-owners, are directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Craig Unit 1 consistent with this Order. SPP, Tri-State and the co-owners shall also provide such additional information regarding the environmental and operational impacts of this Order and its compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

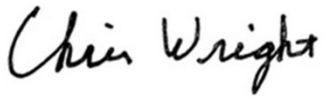
E. Tri-State and the co-owners are directed to file with the Federal Energy Regulatory Commission any tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

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

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

H. This Order shall be effective from June 29, 2026, through September 26, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 26th day of June 2026.



Chris Wright
Secretary of Energy

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

Colorado Public Utilities Commission
Chairman Eric Blank
Commissioner Megan Gilman
Commissioner Tom Plant

EXHIBIT 126

Department of Energy
Washington, DC 20585

Order No. 202-26-20

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

BACKGROUND

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

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

Specifically, I determined that MISO faced tight reserve margins due to well-documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.[5] I determined that the continued operation of

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

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

[4] As a coal-fired facility, it would be difficult for Culley Unit 2 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Culley were to begin disassembling Unit 2 or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

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

Culley Unit 2 would provide additional generation capacity during these periods, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.[6] I determined that the continued operation of Culley Unit 2 was necessary to alleviate immediate and anticipated threats to reliability.[7]

My determination was based on several facts.

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

Second, MISO's year-round resource adequacy concerns are well-documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[10] MISO justified this revision by explaining that "Reliability risks associated with [r]esource [a]dequacy have shifted from 'Summer only' to a year-round concern."[11] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[12]

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[6] *See*, *e.g.*, *id.* at 1–4.

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

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

[9] *Id.* at 44.

[10] *Midcontinent Independent System Operator, Inc.,* FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

[11] *MISO Transmittal Letter*, FERC Docket No. ER22-495-000, at 3 (Nov. 30, 2021).

[12] *Id.* at 3–4.

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order No. 202-25-13 continue, both in the near and long term.[13] The production of electricity from Culley Unit 2 will continue to be critical to maintain reliability in MISO. MISO's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when Culley operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 "MaxGen" event for MISO's North and Central Regions due to generation outages, high demand, and transfer capability limits.[14] From January 21–February 1, 2026, Culley operated at roughly 30 MW almost every day, providing vital generation capacity to the region.[15]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[16] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/2024 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects risk of loss of load in the winter and spring seasons; although not as high as in the summer or fall, losses will nevertheless increase over time.[17]

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[13] Further, as noted in Order No. 202-25-13, as a coal-fired facility, it would be difficult for Culley Unit 2 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. If CenterPoint Energy were to begin disassembling the unit or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required so long as I determine a shortage exists. *See* Order No. 202-25-13 at 1.

[14] *See* Midcontinent ISO on X, (Jan. 24, 2026), https://x.com/MISO_energy/status/2015072060876140805?s=20.

[15] U.S. Dep't of Energy, *FACT SHEET: Energy Department Prevented Blackouts & Saved American Lives During Winter Storms*, (February 2026), https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms.

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

[17] *Id.* at 11.

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative.*"[18] In a section of that report entitled, "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[19] These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.[20] NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,[21] stating that it faces significant reliability challenges as "projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements."[22] This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.[23] The 2025 NERC Long-Term Reliability Assessment notes that "MISO's accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements."[24] The report observes that winter peak periods are a particular concern, with projections showing "shortfalls in planned resources for winter peak periods."[25] However, NERC also concluded that "risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high."[26]

While the 2025–2026 NERC Winter Reliability Assessment found the MISO region to be at normal risk in 2026 and elevated risk in 2027, two earlier winter studies were more critical. The 2023–2024 NERC Winter Reliability Assessment characterized MISO as a region at elevated risk with the "[p]otential for insufficient operating reserves

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[18] MISO, *MISO's Response to the Reliability Imperative* (Updated February 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final 504018.pdf.

[19] *Id.* at 12.

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

[21] *Id.* at 7.

[22] *Id.* at 8.

[23] *Id.* at 43.

[24] *Id.* at 15.

[25] *Id.*

[26] *Id.*

in above-normal conditions."[27] These findings were echoed in NERC's 2024–2025 Winter Reliability Assessment, which noted that "[g]enerating capacity is 10 GW lower (-6.8%) compared to that of the prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[28]

The evidence indicates that there is also a potential longer-term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[29]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their annual survey, which reports the degree to which expected capacity resources satisfy planning reserve margin requirements.[30] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[31] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[32] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[33]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year, while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[34]

Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the

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[27] NERC, *2023 – 2024 Winter Reliability Assessment*, at 5 (Nov. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

[28] NERC, *2024–2025 Winter Reliability Assessment*, at 15 (Nov. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

[29] MISO, *Planning Resource Auction: Results for Planning Year 2025–26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%20250529_Corrections694160.pdf.

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

[31] *Id.* at 2.

[32] *Id.* at 7.

[33] *Id.* at 9.

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

increase in capacity is largely offset by the projected retirements and does not keep up with the growth in demand.[35]

According to the U.S. Energy Information Administration, coal-fired electricity generation in Indiana has declined from 85% of total generation in 2014 to 42% in 2024. Since 2014, approximately 5,000 MW of coal-fired capacity in Indiana have retired, with almost another 3,900 MW of coal-fired capacity scheduled for retirement by the end of 2028, including Culley.[36]

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[37] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away and are provided an additional three-year grace period to commence commercial operations.[38] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[39] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order No. 202-25-13 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and

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[35] *Id*.

[36] *See Electricity,* Energy Information Administration, Indiana Analysis, https://www.eia.gov/states/in/analysis.

[37] *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[38] *Id.* P 84.

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

extraordinary threat to our Nation's economy, national security, and foreign policy."[40] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[41] In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[42]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[43] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth.

Grid operators — including MISO itself — have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[44]

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

[41] *Id*.

[42] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[43] U.S. Dep't of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-11/DOE%20Final%20EO%20Report%20%28REVISED%20OCT%2027%29.pdf.

[44] *Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce*, Subcomm. on Energy, 119th Cong., at 5 (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), https://democrats-energycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/

Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[45] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[46]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[47] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Culley Unit 2 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

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

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Culley Unit 2 shall be made available for operation through June 21, 2026.

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

A. From March 24, 2026, MISO and CenterPoint Energy shall take all measures necessary to ensure that Culley Unit 2 is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Culley Unit 2 to minimize cost to ratepayers. Following the conclusion of this

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files/evo-media-document/witness-testimony_asthana_eng_grid-operators_03.25.2025.pdf.

[45] *Id.* at 6.

[46] *Id.* at 7.

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

Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. CenterPoint Energy is directed to comply with all orders from MISO related to the availability and dispatch of Culley Unit 2.

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

C. All operations of Culley Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.

D. By April 8, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Culley Unit 2 consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

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

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

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

H. This Order shall be effective from March 24, 2026 through June 21, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 23rd day of March 2026.

Chris Wright

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**

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

Indiana Utility Regulatory Commissioners
Chairman Andy Zay
Commissioner Bob Deig
Commissioner Anthony Swinger
Commissioner David Veleta
Commissioner David Ziegner

EXHIBIT 127

Department of Energy
Washington, DC 20585

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

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

BACKGROUND

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

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

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[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

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

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

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

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

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

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

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

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

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

[9] *Id.* at 44.

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

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

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

CONTINUING EMERGENCY CONDITIONS

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

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

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

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

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[12] *Id.* at 3–4.

[13] *See* MISO (@MISO_energy), X, (Jan. 24, 2026), https://x.com/MISO_energy/status/2015072060876140805?s=20.

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

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

[16] *Id.* at 11.

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

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

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

According to NERC's 2026 Summer Reliability Assessment, load growth in the MISO region, led by data centers, "is expected to accelerate in 2027 and beyond, which may lead to increased reliability risk in the future if resource additions cannot keep pace with rising load forecasts."[24] It further notes that "[a]bove-normal summer peak load combined with low resource conditions could result in the need to employ operating mitigations (e.g., load-modifying resources) and EEAs [Energy Emergency Alerts]."[25] Since the region benefits from transmission connections with neighbors to meet extreme conditions, MISO's reliance on electricity imports will increase when extreme conditions arise.[26]

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

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[18] *Id.* at 12.

[19] NERC, *2025 Long-Term Reliability Assessment,* at 7–8 (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[20] *Id.* at 43.

[21] *Id.* at 15.

[22] *Id*.

[23] *Id.*

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

[25] *Id.* at 16.

[26] *Id.* at 16.

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

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

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

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

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

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[27] MISO, *Planning Res. Auction: Results for Planning Year 2025–26*, at 13 (Apr. 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%20202 50529_Corrections694160.pdf.

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

[29] *Id.* at 7.

[30] *Id.* at 9.

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

[32] *Id*.

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

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

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

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

[35] *See id.* P 84.

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

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

[38] *Id*.

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

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

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

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

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

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

[41] *Id.*

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

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

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

ORDER

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

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

I have determined that, to best meet the emergency arising from increased demand, determined shortage and other causes, and serve the public interest under FPA section 202(c), Culley Unit 2 shall be made available for operation through September 19, 2026.

[44] *Id.* at 6.

[45] *Id.* at 7.

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

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

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

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

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

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

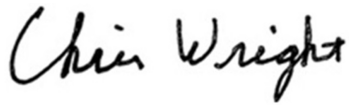
E. CenterPoint Energy is directed to file with the Federal Energy Regulatory Commission any tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

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

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

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

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



Chris Wright
Secretary of Energy

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

Indiana Utility Regulatory Commissioners
Chairman Andy Zay
Commissioner Bob Deig
Commissioner Anthony Swinger
Commissioner David Veleta
Commissioner David Ziegner

EXHIBIT 128

Department of Energy
Washington, DC 20585

Order No. 202-25-12

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

BACKGROUND

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

EMERGENCY SITUATION

Midcontinent Independent System Operator, Inc.'s (MISO) year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[5] MISO justified this revision by explaining that "Reliability risks associated with Resource Adequacy have shifted from 'Summer only' to a year-round concern."[6] MISO noted that over 60% of all

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] U.S. Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024), https://www.eia.gov/electricity/data/eia860/.
[4] As coal-fired facilities, it would be difficult for the Schahfer Units 17 and 18 to resume operations once they have been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Schahfer were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.
[5] *Midcontinent Independent System Operator, Inc.,* FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).
[6] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).

"MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[7]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[8] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[9]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative."*[10] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season:

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[11]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season. The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO.

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area is at an elevated risk "because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years."[12]

When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[13]

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[7] *Id.* at 3-4.
[8] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[9] *Id.* at 11.
[10] MISO, *MISO's Response to the Reliability Imperative* (Updated February 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[11] *Id.* at 12.
[12] *NERC 2024 Long-Term Reliability Assessment*, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
[13] MISO, *Planning Resource Auction: Results for Planning Year 2025-26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[14] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[15] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[16] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[17]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large quantities of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[18] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[19]

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[20] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.[21] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[22] Consequently, it is not at all clear that the new ERAS process will result in the addition of new capacity in the next few years.

More broadly, executive orders issued by President Donald J. Trump on January 20, 2025 and April 8, 2025, underscored the dire energy challenges facing the Nation due to growing

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

[15] *Id.* at 2.

[16] *Id.* at 7.

[17] *Id.* at 9.

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

[19] *Id*.

[20] *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[21] *Id.* P 84.

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

resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[23] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[24] In a subsequent Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[25]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[26]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[27] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Schahfer Units 17 and 18 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

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

[23] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.
[24] *Id*.
[25] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.
[26] U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025.07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.
[27] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of Energy. *See* 42 U.S.C. § 7151(b).

identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of Schahfer Units 17 and 18 is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c).

To ensure Schahfer Units 17 and 18 will be available if needed to address emergency conditions, Schahfer Units 17 and 18 shall remain in operation until March 23, 2026.

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

A. From December 23, 2025, MISO and NIPSCO, shall take all measures necessary to ensure that Schahfer Units 17 and 18 are available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Schahfer Units 17 and 18 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. NIPSCO is directed to comply with all orders from MISO related to the availability and dispatch of the Schahfer Units 17 and 18.

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

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

D. By January 13, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Schahfer Units 17 and 18 consistent with this Order. MISO and NIPSCO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

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

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

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

H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 23, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 23, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Denver, Colorado at 6:39 PM EST on this 23rd day of December 2025.

Chris Wright
Secretary of Energy

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

Indiana Utility Regulatory Commission
Chairman Jim Huston
Commissioner David Veleta
Commissioner David Ziegner

EXHIBIT 129

Department of Energy
Washington, DC 20585

Order No. 202-26-19

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

BACKGROUND

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

Order No. 202-25-12, issued pursuant to FPA section 202(c), required that Schahfer remain in operation for 90 days, through March 23, 2026. This order was based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO).

Specifically, I determined that MISO faced tight reserve margins due to well documented year-round resource adequacy concerns, particularly during periods of high

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

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

[4] As coal-fired facilities, it would be difficult for Schahfer Units 17 and 18 to resume operations once they have been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Schahfer were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

demand or low generation resource output.[5] I determined that the continued operation of Schahfer would provide additional generation capacity during these periods, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.[6] I determined that the continued operation of Schahfer was necessary to alleviate immediate and anticipated threats to reliability.[7]

My determination was based on several facts.

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

Second, MISO's year-round resource adequacy concerns are well-documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction (PRA)) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[10] MISO justified this revision by explaining that "Reliability risks associated with [r]esource [a]dequacy have shifted from 'Summer only' to a year-round concern."[11] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[12]

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

[6] *See, e.g.*, *id.* at 1–4.

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

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

[9] *Id.* at 44.

[10] *Midcontinent Independent System Operator, Inc.,* FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

[11] *MISO Transmittal Letter*, FERC Docket No. ER22-495-000, at 3 (Nov. 30, 2021).

[12] *Id.* at 3–4.

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order No. 202-25-12 continue, both in the near and long term.[13] The production of electricity from Schahfer will continue to be critical to maintain reliability in MISO. MISO's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when Schahfer operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 "MaxGen" event for MISO's North and Central Regions due to generation outages, high demand, and transfer capability limits.[14] From January 21–February 1, 2026, Schahfer operated at over 285 MW every day.[15]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[16] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/2024 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected risk of loss of load in the winter and spring seasons, which, although not as high as in the summer or fall, will nevertheless increase over time.[17]

[13] Further, as noted in Order No. 202-25-12, as a coal-fired facility, it would be difficult for Schahfer to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. If NIPSCO were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required so long as I determine a shortage exists. *See* Order No. 202-25-12 at 1.

[14] *See* Midcontinent ISO on X, (Jan. 24, 2026), https://x.com/MISO_energy/status/2015072060876140805?s=20.

[15] U.S. Dep't of Energy, *FACT SHEET: Energy Department Prevented Blackouts & Saved American Lives During Winter Storms*, (February 2026), https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms.

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

[17] *Id.* at 11.

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative*."[18] In a section of that report entitled, "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[19] These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.[20] NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,[21] stating that it faces significant reliability challenges as "projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements."[22] This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.[23] The 2025 NERC Long-Term Reliability Assessment notes that "MISO's accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements."[24] The report observes that winter peak periods are a particular concern, with projections showing "shortfalls in planned resources for winter peak periods."[25] However, NERC also concluded that "risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high."[26]

While the 2025–2026 NERC Winter Reliability Assessment found the MISO region to be at normal risk in 2026 and elevated risk in 2027, two earlier winter studies were more critical. The 2023–2024 NERC Winter Reliability Assessment characterized MISO as a region at elevated risk with the "[p]otential for insufficient operating reserves

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

[19] *Id.* at 12.

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

[21] *Id.* at 7.

[22] *Id.* at 8.

[23] *Id.* at 43.

[24] *Id.* at 15.

[25] *Id.*

[26] *Id.*

in above-normal conditions."[27] These findings were echoed in NERC's 2024–2025 Winter Reliability Assessment, which noted that "[g]enerating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[28]

The evidence indicates that there is also a potential longer-term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025–26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[29]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their annual survey, which reported the degree to which expected capacity resources satisfy planning reserve margin requirements.[30] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[31] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[32] It also projected similar results for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[33]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year, while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[34]

Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the

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[27] NERC, *2023–2024 Winter Reliability Assessment*, at 5 (Nov. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

[28] NERC, *2024–2025 Winter Reliability Assessment*, at 15 (Nov. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

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

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

[31] *Id.* at 2.

[32] *Id.* at 7.

[33] *Id.* at 9.

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

increase in capacity is largely offset by the projected retirements and does not keep up with the growth in demand.[35]

According to the U.S. Energy Information Administration, coal-fired electricity generation in Indiana has declined from 85% of total generation in 2014 to 42% in 2024. Since 2014, approximately 5,000 MW of coal-fired capacity in Indiana have retired, with almost another 3,900 MW of coal-fired capacity scheduled for retirement by the end of 2028, including Schahfer.[36]

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[37] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away and are provided an additional three-year grace period to commence commercial operations.[38] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[39] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order No. 202-25-12 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and

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[35] *Id*.

[36] *See Electricity,* Energy Information Administration, Indiana Analysis, https://www.eia.gov/states/in/analysis.

[37] *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[38] *Id.* P 84.

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

extraordinary threat to our Nation's economy, national security, and foreign policy."[40] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[41] In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[42]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[43] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth.

Grid operators—including MISO itself—have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[44]

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

[41] *Id*.

[42] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[43] U.S. Dep't of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-11/DOE%20Final%20EO%20Report%20%28REVISED%20OCT%2027%29.pdf.

[44] *Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce*, Subcomm. on Energy, 119th Cong., at 5 (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), https://democrats-energycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/

Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[45] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[46]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[47] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Schahfer Units 17 and 18 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

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

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Schahfer Units 17 and 18 shall be made available for operation through June 21, 2026.

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

A. From March 24, 2026, MISO and NIPSCO, shall take all measures necessary to ensure that Schahfer Units 17 and 18 are available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Schahfer Units 17 and 18 to minimize cost to ratepayers. Following the

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files/evo-media-document/witness-testimony_asthana_eng_grid-operators_03.25.2025.pdf.

[45] *Id.* at 6.

[46] *Id.* at 7.

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

conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. NIPSCO is directed to comply with all orders from MISO related to the availability and dispatch of Schahfer Units 17 and 18.

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

C. All operation of Schahfer must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.

D. By April 8, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Schahfer Units 17 and 18 consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

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

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

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

H. This Order shall be effective from March 24, 2026 through June 21, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 23rd day of March 2026.

Chris Wright

Chris Wright
Secretary of Energy

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

Indiana Utility Regulatory Commissioners
Chairman Andy Zay
Commissioner Bob Deig
Commissioner Anthony Swinger
Commissioner David Veleta
Commissioner David Ziegner

EXHIBIT 130

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

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

BACKGROUND

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

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

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

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

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

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

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

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

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

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

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

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

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

[9] *Id.* at 44.

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

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

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

CONTINUING EMERGENCY CONDITIONS

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

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

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

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

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[12] *Id.* at 3–4.

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

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

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

[16] *Id.* at 11.

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

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

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

According to NERC's 2026 Summer Reliability Assessment, load growth in the MISO region, led by data centers, "is expected to accelerate in 2027 and beyond, which may lead to increased reliability risk in the future if resource additions cannot keep pace with rising load forecasts."[24] It further notes that "[a]bove-normal summer peak load combined with low resource conditions could result in the need to employ operating mitigations (e.g., load-modifying resources) and EEAs [Energy Emergency Alerts]."[25] Since the region benefits from transmission connections with neighbors to meet extreme conditions, MISO's reliance on electricity imports will increase when extreme conditions arise.[26]

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

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[18] *Id.* at 12.

[19] NERC, *2025 Long-Term Reliability Assessment,* at 7–8 (Jan. 2026), https://prod.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[20] *Id.* at 43.

[21] *Id.* at 15.

[22] *Id*.

[23] *Id.*

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

[25] *Id.* at 16.

[26] *Id.* at 16.

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

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

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

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

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

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

[29] *Id.* at 7.

[30] *Id.* at 9.

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

[32] *Id*.

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

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

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

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

[35] *See id.* P 84.

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

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

[38] *Id*.

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

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

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

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

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

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

[41] *Id.*

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

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

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

ORDER

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

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

I have determined that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Schahfer Units 17 and 18 shall be made available for operation through September 19, 2026.

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[44] *Id.* at 6.

[45] *Id.* at 7.

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

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

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

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

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

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

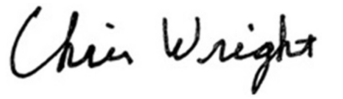
E. NIPSCO is directed to file with the Federal Energy Regulatory Commission any tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

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

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

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

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



Chris Wright
Secretary of Energy

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

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