BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-26-18

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

Exhibit 2-61:
Department Export Authorizations Library

U.S. DEPARTMENT of ENERGY

Grid Deployment Office Export Authorization Library

Export Authorization Library

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Search:

Docket No.	Company Name	Country	Date Issued	Status	Date Expires
EA-365-C	Research Power Corporation	Canada	10/21/2025	Active	10/21/2030
EA-408-B	Nalcor Energy Marketing Corporation (NEMC)	Canada	10/17/2025	Active	10/17/2030
EA-479-A	Macquarie Energy LLC	Canada	7/11/2025	Active	7/11/2030
EA-284-G	Calpine Energy	Mexico	6/10/2025	Active	6/10/2030
EA-520	XTS LLC	Mexico	6/10/2025	Active	6/10/2030
EA-171-F	Powerex Corp.	Canada	6/10/2025	Active	6/10/2030
EA-519	Oiko Energy Inc.	Canada	6/10/2025	Active	5/27/2030
EA-517	Altop Energy Investments LP	Mexico	5/23/2025	Active	5/23/2030
EA-518	Altop Energy Investments LP	Canada	5/21/2025	Active	5/21/2030
EA-516	Energia Sierra Juarez U.S., LLC	Mexico	5/16/2025	Active	
EA-391-B	Emera Energy Services Subsidiary No. 6 LLC	Canada	10/15/2024	Active	2/21/2029
EA-392-B	Emera Energy Services Subsidiary No. 7 LLC	Canada	10/15/2024	Active	2/21/2029
EA-393-B	Emera Energy Services Subsidiary No. 8 LLC	Canada	10/15/2024	Active	2/21/2029
EA-504	AlbertaEx, L.P.	Canada	10/9/2024	Active	10/9/2029
EA-475-A	Idaho Power Company	Canada	9/26/2024	Active	9/26/2029
EA-473-A	Northland Power and Energy Marketing, Inc.	Canada	9/24/2024	Active	9/24/2029
EA-264-E	ENMAX Energy Market Inc.	Canada	9/24/2024	Active	9/24/2029
EA-512	ATNV Energy, LP	Mexico	9/20/2024	Active	9/20/2029
EA-515	AMA QSE, LLC	Mexico	9/20/2024	Active	9/20/2029
EA-249-E	Constellation Energy Generation, LLC	Canada	9/20/2024	Active	9/20/2029
EA-97-F	Portland General Electric Company	Canada	9/20/2024	Active	6/25/2034
EA-514	Altop Energy Trading Texas LLC	Mexico	9/6/2024	Active	9/6/2029
EA-456-A	Manifold Energy Inc	Canada	9/6/2024	Expired	9/6/2024
EA-513	Altop Energy	Canada	9/6/2024	Active	9/6/2029

Docket No.	Company Name	Country	Date Issued	Status	Date Expires
EA-427 (E-6751)	Versant Power	Canada	8/26/2024	Active	8/26/2029
EA-510	MFT Energy US Power LLC	Mexico	8/13/2024	Active	8/15/2029
EA-470-A	EDECSAMEX, S.A. de C.V.	Mexico	8/13/2024	Active	8/15/2029
EA-511	ATNV Energy, LP	Canada	8/13/2024	Active	8/15/2029
EA-312-D	Emera Energy U.S. Subsidiary No. 2, Inc.	Canada	7/31/2024	Expired	5/5/2025
EA-466-A	Dynasty Power, Inc.	Mexico	7/31/2024	Active	8/2/2029
EA-466-A	Dynasty Power, Inc.	Mexico	7/31/2024	Active	8/2/2029
EA-385-B	Dynasty Power, Inc.	Canada	7/31/2024	Active	7/31/2029
EA-385-B	Dynasty Power, Inc.	Canada	7/31/2024	Active	8/2/2029
EA-312-C	Emera Energy U.S. Subsidiary No. 2, Inc.	Canada	7/31/2024	Active	7/31/2029
EA-312-C	Emera Energy U.S. Subsidiary No. 2, Inc.	Canada	7/31/2024	Active	8/2/2029
EA-469-A	Puget Sound Energy	Canada	7/31/2024	Active	8/2/2029
EA-469-A	Puget Sound Energy	Canada	7/31/2024	Active	8/2/2029
EA-471-A	Luminant Energy Company LLC	Mexico	6/5/2024	Active	6/5/2029
EA-467-A	Citigroup Commodities Canada ULC	Canada	5/9/2024	Active	5/9/2029
EA-348-D	NextEra Energy Marketing, LLC	Canada	3/21/2024	Active	7/10/2029
EA-260-G	CP Energy Marketing (US) Inc.	Canada	3/11/2024	Active	5/29/2029
EA-145-G	Powerex Corp	Mexico	2/27/2024	Active	4/16/2029
EA-508	ENGIE Energy Marketing NA, Inc.	Mexico	2/26/2024	Active	6/24/2029
EA-464-A	Boston Energy Trading and Marketing LLC	Mexico	2/21/2024	Active	2/21/2029
EA-458-A	Sempra Gas and Power Marketing, LLC	Mexico	2/16/2024	Active	2/16/2029
EA-472-A	Luminant Energy Company LLC	Canada	2/13/2024	Active	6/5/2029
EA-509	Merelec USA	Mexico	1/29/2024	Active	7/10/2029
EA-465-A	Brookfield Renewable Trading and Marketing LP	Canada	1/11/2024	Active	3/25/2029
EA-506	Second Foundation US Trading LLC	Canada	1/8/2024	Active	4/16/2029
EA-507	Second Foundation US Trading LLC	Mexico	1/8/2024	Active	4/16/2029
EA-497-A	NRG Business Marketing LLC	Mexico	12/29/2023	Active	4/10/2028
EA-498-A	NRG Business Marketing LLC	Canada	12/29/2023	Active	9/21/2028
EA-505	Altop Energy	Mexico	12/28/2023	Active	4/16/2029
EA-287-E	Emera Energy U.S. Subsidiary No. 1, Inc.	Canada	12/20/2023	Expired	5/21/2025
EA-503	CWP Energy, Inc.	Mexico	12/19/2023	Active	12/19/2028
EA-287-D	Emera Energy U.S. Subsidiary No. 1	Canada	12/19/2023	Active	12/19/2028
EA-388-B	TEC Energy Inc.	Canada	12/18/2023	Active	12/18/2028
EA-462-A	Guzman Energy LLC	Mexico	12/18/2023	Active	12/18/2028
EA-455-A	NS Power Energy Marketing Incorporated	Canada	11/18/2023	Active	11/8/2028
EA-345-C	New Brunswick Energy Marketing Corporation	Canada	11/16/2023	Active	11/16/2028

Docket No.	Company Name	Country	Date Issued	Status	Date Expires
EA-459-B	Mercuria Energy America, LLC	Mexico	11/16/2023	Active	11/16/2028
EA-461-A	Saavi Energy Solutions, LLC	Mexico	11/16/2023	Active	11/16/2028
EA-468-A	TransCanada Energy Sales Ltd.	Canada	11/14/2023	Active	2/16/2029
EA-463-A	Boston Energy Trading and Marketing LLC	Canada	11/14/2023	Active	2/16/2029
EA-342-C	Royal Bank of Canada	Canada	11/8/2023	Active	11/8/2028
EA-500	MFT Energy US Power LLC	Canada	11/8/2023	Active	11/8/2028
EA-502	In Commodities	Canada	11/8/2023	Active	11/8/2028
EA-257-F	Emera Energy Services, Inc.	Canada	10/25/2023	Active	2/21/2029
EA-257-F	Emera Energy Services, Inc.	Canada	10/25/2023	Active	12/30/2029
EA-257-F	Emera Energy Services, Inc.	Canada	10/25/2023	Active	2/21/2029
EA-257-F	Emera Energy Services, Inc.	Canada	10/25/2023	Active	12/30/2029
EA-108-A	Arizona Public Service Company	Mexico	10/6/2023	Active	
EA-497	Direct Energy Business Marketing, LLC	Mexico	9/21/2023	Active	9/21/2028
EA-499	Elektron Power LLC	Mexico	9/21/2023	Active	9/21/2028
EA-498	Direct Energy Business Marketing, LLC	Canada	9/21/2023	Active	9/21/2028
EA-196-F	Minnesota Power	Canada	9/21/2023	Active	9/21/2028
EA-321-C	Emera Energy Services Subsidiary No. 1 LLC	Canada	8/24/2023	Active	8/24/2028
EA-322-C	Emera Energy Services Subsidiary No. 2 LLC	Canada	8/24/2023	Active	8/14/2028
EA-323-C	Emera Energy Services Subsidiary No. 3 LLC	Canada	8/24/2023	Active	8/24/2028
EA-324-C	Emera Energy Services Subsidiary No. 4 LLC	Canada	8/24/2023	Active	8/24/2028
EA-325-C	Emera Energy Services Subsidiary No. 5 LLC	Canada	8/24/2023	Active	8/24/2028
EA-453-A	Matador Power Marketing, Inc.	Canada	7/6/2023	Active	7/6/2028
EA-452-A	Matador Power Marketing, Inc.	Mexico	7/6/2023	Active	7/6/2028
EA-444-A	Emera Energy Services Subsidiary No. 9 LLC	Canada	6/26/2023	Active	6/26/2028
EA-445-A	Emera Energy Services Subsidiary No. 10 LLC	Canada	6/26/2023	Active	6/26/2028
EA-446-A	Emera Energy Services Subsidiary No. 11 LLC	Canada	6/26/2023	Active	6/26/2028
EA-447-A	Emera Energy Services Subsidiary No. 12 LLC	Canada	6/26/2023	Active	6/26/2028
EA-448-A	Emera Energy Services Subsidiary No. 13 LLC	Canada	6/26/2023	Active	6/26/2028
EA-449-A	Emera Energy LNG, LLC	Canada	6/26/2023	Active	6/26/2028
EA-450-A	Emera Energy Services Subsidiary No. 15 LLC	Canada	6/26/2023	Active	6/26/2028
EA-349-C	Bruce Power Inc.	Canada	6/21/2023	Expired	6/21/2023
EA-501	EDC Power, LLC	Mexico	6/12/2023	Active	6/12/2028
EA-380-A	Freepoint Commodities LLC	Canada	6/12/2023	Active	6/12/2028
EA-336-C	ConocoPhillips Company	Mexico	6/12/2023	Active	6/12/2028
EA-318-D	AEP Energy Partners	Mexico	5/2/2023	Active	5/2/2028
EA-339-C	Shell Energy North America	Canada	5/2/2023	Active	5/23/2028
EA-296-D	Rainbow Energy Marketing Corporation	Canada	5/2/2023	Active	5/2/2028

Docket No.	Company Name	Country	Date Issued	Status	Date Expires
EA-338-C	Shell Energy North America	Mexico	5/2/2023	Active	5/2/2028
EA-496	Command Power Corp.	Canada	5/2/2023	Active	5/2/2028
EA-436-A	MAG Energy Solutions, Inc	Mexico	8/11/2022	Active	9/28/2027

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-26-18

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

Exhibit 2-62:
Department Export Authorization EA-365-C (Oct. 21, 2025)

United States
Department of Energy

Grid Deployment Office

Research Power Corporation
(formerly known as Centre Lane Trading Ltd.)
GDO Docket No. EA-365-C

Order Authorizing Electricity Exports to Canada

Order No. EA-365-C

October 21, 2025

Research Power Corporation
(formerly known as Centre Lane Trading Ltd.)
Order No. EA-365-C
Authorizing Electricity Exports to Canada

I. BACKGROUND

The Department of Energy (DOE or Department) regulates electricity exports from the United States to a foreign country in accordance with Federal Power Act (FPA) § 202(e) (16 U.S.C. § 824a(e)) and regulations thereunder (10 C.F.R. §§ 205.300 *et seq.*). This authority was transferred to DOE under §§ 301(b) and 402(f) of the DOE Organization Act (42 U.S.C. §§ 7151(b) and 7172(f)). On April 10, 2023, this authority was delegated to the DOE's Grid Deployment Office (GDO) by Redelegation Order No. S3-DEL-GD1-2023.

An entity that seeks to export electricity must obtain an order from DOE authorizing it to do so. Under FPA § 202(e), DOE "shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has discretion to condition the order as necessary or appropriate; the Department "may by its order grant such application in whole or in part, with such modifications and upon such terms and conditions as [DOE] may find necessary or appropriate, and may from time to time, after opportunity for hearing and for good cause shown, make such supplemental orders in the premises as it may find necessary or appropriate." *Id*.

A. Application for Export Authorization

Research Power Corporation (the Applicant) is a power marketer seeking renewal of its authorization to export electric energy to Canada, which was originally granted in Order No. EA-365-A on June 29, 2015, and subsequently renewed (EA-365-B) on April 29, 2020. On December 26, 2024, Centre Lane filed an application with DOE (Application or App.) requesting renewal of its export authority for a five-year term. App. at 1. On July 7, 2025, the Applicant notified DOE of its corporate name change from Centre Lane Trading Ltd. to Research Power Corporation.

According to the Application, Research Power Corporation (formerly known as Centre Lane Trading Ltd.) "is a Canadian Corporation with its principal place of business in Toronto, Ontario" that is "organized under the *Business Corporations Act* of the Province of Ontario, Canada." *Id*. The Applicant states that it "does not own, operate or control any generation or transmission facilities in any region, nor is it affiliated with any entity that owns, operates or controls generation or transmission facilities, and is not affiliated with any franchised public utility." *Id* at 1-2. The applicant further represents that it is a "[Federal Energy Regulatory Commission]-authorized power marketer engaging in the purchase and sale of physical and/or virtual energy in the Day-ahead and Real-time Markets of various Independent System Operators and Regional Transmission Organizations." App at 2.

Research Power Corporation represents that it "has no electric power supply system on which the proposed exports could have a reliability, fuel use system or stability impact." App. at 3. The Applicant states that it "has no obligation to serve native load usually associated with a franchised service area, and, thus, the exports proposed by [Research Power Corporation] will not impair its ability to meet current and prospective power supply obligations." *Id.* The Applicant further affirms that it "will purchase power to be exported from a variety of sources such as power marketers, independent power producers, or U.S. electric utilities and federal power marketing entities as those terms are defined in Sections 3(22) and 3(19) of the FPA" and that "such power is surplus to the system of the generator and, therefore, the electric power that [Research Power Corporation] will export on either a firm or interruptible basis will not impair the sufficiency of the electric power supply within the U.S." *Id*.

The applicant states that it "will make all necessary commercial arrangements and will obtain any and all other regulatory approvals required in order to schedule and deliver power exports." *Id*. The Applicant further states that it will "schedule its transactions with the appropriate balancing authority areas in compliance with the reliability criteria standards and guidelines established by the North American Electric Reliability Corporation[.]" *Id*. Research Power Corporation also attests to not exceed the export limits for the facilities, or otherwise cause a violation of the terms and conditions set forth in the export authorizations for each. App at 4.

B. Procedural History

On December 26, 2024, Centre Lane filed a renewal application with DOE for export authority for a five-year term. *Id* at 1. On June 16, 2025, DOE published notice of Centre Lane's Application in the Federal Register (90 Fed. Reg. 25252) and asked for any interested parties to submit comments on the Application by July 16, 2025. On July 7, 2025, DOE received notice of Centre Lane's corporate name change to Research Power Corporation.

C. Public Comments

No public comments were received.

II. DISCUSSION AND ANALYSIS

DOE is statutorily obligated under FPA § 202(e) to grant requests for export authorization unless the Department finds that the proposed export would negatively impact either: (i) the sufficiency of electric supply, or (ii) the coordination of the electric grid. Regarding the first exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States …." 16 U.S.C. § 824a(e). DOE has interpreted this criterion to mean that sufficient generating capacity and electric energy must exist such that the export could be made without compromising the energy needs of the exporting region, including serving all load obligations in the region while maintaining appropriate reserve levels. *See, e.g.*, *BP Energy Co.*, Order No. EA-314, at 1-2 (Feb. 22, 2007), *renewed*, Order No. EA-314-A, at 2 (May 3, 2012), Order No. EA-314-B, at 2 (Feb. 28, 2017), *renewed,* Order No. EA-314-C, at 4 (Dec. 20, 2021).

Under the second exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would … impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has interpreted this criterion primarily as an issue of the operational reliability of the domestic electric transmission system. Accordingly, the export must not compromise transmission system security and reliability. *See, e.g.*, Order No. EA-314-C, at 4.

A. Research Power Corporation Will Not Impair the Sufficiency of the Electric Supply in the United States

Sufficiency of supply, the first exception criterion, addresses whether regional electricity needs are met in the current market. DOE has analyzed this issue from both an economic and a reliability perspective. The economic perspective concerns the supply available to wholesale market participants. The reliability perspective focuses on preventing problems that could result from inadequate supplies. Taken together, DOE examines whether existing electric supply is available via market mechanisms, and whether potential reliability issues linked to supply problems are mitigated by reliability enforcement mechanisms.

From an economic perspective, DOE finds that the wholesale energy markets are sufficiently robust to make supplies available to exporters and other market participants serving United States regions along the Canadian and Mexican borders. Following enactment of the Energy Policy Act of 1992, Pub. L. No. 102-486, which encouraged the Federal Energy Regulatory Commission (FERC) to foster competition in the wholesale energy markets through open access to transmission facilities, energy markets developed across the United States to provide opportunities for a more efficient availability of supply. Subsequently, the Energy Policy Act of 2005, Pub. L. No. 109-58, reaffirmed the Government's commitment to competition in wholesale energy markets as national policy. FERC has continued to encourage the expansion of wholesale energy markets through its orders to remove barriers[1] and to ensure that these markets are functioning properly.[2] As a result, market participants have access to traditional bilateral contracts, as well as organized electricity markets run by regional transmission organizations (RTOs) or independent system operators (ISOs). FERC oversees these interstate wholesale electricity markets across most of the lower 48 states. Absent an indication in the record that the geographic markets relevant to this export authorization analysis are flawed and result in

[1] *See, e.g.*, *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

[2] *See, e.g.*, *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *as amended*, 126 FERC ¶ 61,261, *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

uneconomic exports that jeopardize regional supply, DOE finds that the proposed transmission for export does not impair the sufficiency of electric supply within the United States.

From a reliability perspective,[3] DOE focuses on the prevention of cascading outages and other problems that could result from inadequate resources.[4] Reliability oversight is addressed by the authority granted to FERC through the Energy Policy Act of 2005. That Act added section 215 to the FPA, which directed FERC to certify an electric reliability organization and develop procedures for establishing, approving, and enforcing mandatory electric reliability standards. 16 U.S.C. § 824o. FERC certified the North American Electric Reliability Corporation (NERC) in 2006 to develop and enforce reliability standards for the bulk-power system in the United States. *Order Certifying NERC as the Electric Reliability Organization and Ordering Compliance Filing*, FERC Docket No. RR06-1-000, 116 FERC ¶ 61,062 (July 20, 2006). FERC approves these standards, at which point they become mandatory and enforceable. NERC Reliability Standards address areas such as resource and demand balancing, critical infrastructure protection, communications, emergency preparedness and operations, facilities design, transmission operations, transmission planning, modelling, nuclear, personnel performance and training, protection and controls, voltage and reactive, interchange scheduling and coordination, and interconnection reliability operations and coordination.

NERC Reliability Standards are enforceable throughout the continental United States, most of Canada south of the 60th parallel, and the Mexican state of Baja California Norte. Through enforcement by FERC, NERC, and six Regional Entities overseen by NERC,[5] all bulk-power system owners, operators, and users are held responsible for complying with reliability standards. The reliability standards are structured so that many entities have overlapping responsibility for the electric grid, thereby resulting in several layers of reliability monitoring. Entities such as reliability coordinators and balancing authorities coordinate power generation and transmission among multiple utilities to serve demand within an integrated regional wholesale market. One of the principal functions of these entities is to schedule adequate generating and reserve capacity. This allows them to serve demand at the regional level and to ensure that there is sufficient power supply to maintain system reliability. Reliability Standard IRO-001-4 "establish[es] the responsibility of Reliability Coordinators to act or direct other entities to act."[6] Requirement R1 states that "[e]ach Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions."[7] Reliability oversight is designed through coordinated efforts amongst Reliability Coordinators to preserve the benefits of interconnected operations and ensure that operations in one area will not adversely impact other areas.[8] Reliability Standard IRO-014-3 R1 provides that "[e]ach Reliability Coordinator shall have and implement Operating Procedures, Operating

[3] A related reliability analysis follows in the next section of this Order.

[4] This focus should not be confused with resource adequacy planning and capacity requirements that have traditionally been the domain of state regulatory commissions, NERC-certified Regional Entities, and RTOs/ISOs.

[5] The six entities are the Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst Corporation, SERC Reliability Corporation, Texas Reliability Entity, and Western Electricity Coordinating Council.

[6] Standard IRO-001-4 (Reliability Coordination – Responsibilities), at ¶ A.3.

[7] *Id.* ¶ B.R1.

[8] *See* Standard IRO-014-3 (Coordination Among Reliability Coordinators), at ¶ A.3.

Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability."[9]

DOE finds that NERC's FERC-approved comprehensive enforcement mechanism ensures that bulk-power system owners, operators, and users have a strong incentive both to maintain system resources and to prevent reliability problems that could result from movement of electric supplies through export. As a result of this reliability oversight, DOE finds that the sufficiency of supply is not impaired by Research Power Corporation's proposed export authorization.

DOE's sufficiency of supply findings are further supported by the fact that power marketers, such as Research Power Corporation, do not have an obligation to serve a franchised territory. Before the current role of power marketers emerged in the industry, the FPA § 202(e) inquiry into sufficiency of supply had a narrower focus and was designed for an applicant that was a vertically integrated utility[10] with an obligation to serve native load. Under that traditional scenario, the inquiry regarding sufficiency of supply logically sought to confirm that exports would be surplus to the needs of a vertically-integrated utility's native load obligations and reserve margins. As explained in DOE's notice of the first application by a power marketer for export authorization, the sufficiency of supply inquiry became unnecessary when applied to power marketers:

> The Applicant also is required to demonstrate that it would have sufficient generating capacity to sustain the proposed export under the terms and conditions of its export agreement, while still complying with any established reserve criteria.
>
> Since marketers generally could not be seen as having any "native load" requirements, the latter criterion of maintaining sufficient reserve margins appears inappropriate and unnecessary in this instance.

59 Fed. Reg. 54900 (Nov. 2, 1994). Power marketers do not have franchised service areas and, consequently, do not have native load obligations like a traditional local distribution utility that could be impaired by exports.

In sum, market mechanisms and reliability oversight protect against the possibility that Research Power Corporation's exports would jeopardize domestic sufficiency of supply. Therefore, an export by Research Power Corporation would not trigger the first exception criterion of FPA § 202(e) regarding the sufficiency of electric supply within the United States.

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[9] *Id.* ¶ B.R1.

[10] The Supreme Court of the United States has explained: "In 1935, when the FPA became law, most electricity was sold by vertically integrated utilities that had constructed their own power plants, transmission lines, and local delivery systems…[M]ost operated as separate, local monopolies subject to state or local regulation. Their sales were 'bundled,' meaning that consumers paid a single charge that included both the cost of the electric energy and the cost of its delivery. Competition among utilities was not prevalent." *New York v. FERC*, 535 US 1, 5 (2002).

B. Research Power Corporation's Requested Authorization Will Not Adversely Affect Either the Reliability or the Security of the United States Electric Transmission System

Reliability, the second exception criterion under FPA § 202(e), addresses operational reliability and security of the domestic electric transmission system. In evaluating the operational reliability impacts of export proposals, DOE has used a variety of methodologies and information, including established industry guidelines, operating procedures, and technical studies where available and appropriate. When determining these impacts, it is convenient to separate the export transaction into two parts: (i) moving the export from the source to a border system that owns the international transmission connection, and (ii) moving the export through that border system and across the border.

Moving Electricity to a Border System. Moving electricity for export to a border system necessarily involves the use of the bulk-power system. As noted in the preceding section, bulk-power system reliability concerns are addressed under the FPA by FERC and NERC and involve the enforcement of mandatory reliability standards. These standards ensure that all owners, operators, and users of the bulk-power system have an obligation to maintain system security and reliability. The standards are structured so that there are always entities with broader responsibilities than the applicant, such as reliability coordinators and balancing authorities, to keep a constant watch over the domestic transmission system.

To deliver the export from the source to a border system, the applicant must make the necessary commercial arrangements and obtain sufficient transmission capacity to wheel the exported energy to the border system. The applicant would be expected to follow FERC orders regarding open transmission access and to schedule delivery of the export with the appropriate RTO, ISO, and/or balancing authority (formerly the control area operator).

It is the responsibility of the RTO, ISO, and/or balancing authority to schedule the delivery of the export consistent with established and mandatory operational reliability criteria. During each step of the process of obtaining transmission service, the owners and/or operators of the transmission facilities will evaluate the impact on the system and schedule the movement of the export *only* if it would not violate established operating reliability standards. As a failsafe, the reliability coordinator in each region has the authority and responsibility to curtail, cancel, or deny scheduled flows to avoid shortages or to restore necessary energy and capacity reserves. Reliability Standard EOP-011-1 R2 provides that "[e]ach Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area."[11]

Specifically, the reliability coordinator has the authority to suspend exports if the electric energy would be needed to support the regional power grid. *See* Reliability Standard IRO-001-4 R1 ("Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions"), R2 ("Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the

[11] EOP-011-1 (Emergency Operations), at ¶ B.R2.

Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements"), and R3 ("Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1").

DOE has determined that the existing industry procedures for obtaining transmission capacity on the domestic transmission system (described above) provide adequate assurance that any export will not cause an operational reliability problem. Therefore, Research Power Corporation's export authorization has been conditioned to ensure that the export will not cause operational issues on regional transmission systems to fall outside of established industry reliability criteria, or cause or exacerbate a transmission operating problem on the United States' electric power supply system (*see* Order below, Section VII, paragraphs C, D, and I).

Moving Electricity Through a Border System. The second part of DOE's reliability inquiry, addressing the transmission of the export through a border system and across the border, is a question of whether the border system is reliable and secure. To a large extent, this question is addressed by the jurisdiction of NERC. NERC and Regional Entities—including the Midwest Reliability Organization, the Northeast Power Coordinating Council, and the Western Electricity Coordinating Council—oversee the United States-Canadian border system and a significant part of the United States-Mexican border system. Those border systems are generally subject to the same reliability standards as domestic systems. *See, e.g.*, http://www.ieso.ca/sector-participants/system-reliability/reliability-standards-framework.

DOE also relies on the System Impact Studies submitted in conjunction with an application for a DOE-issued Presidential permit[12] to construct a new international transmission line. As DOE has previously reviewed System Impact Studies submitted with Presidential permit applications,[13] DOE does not need to perform additional impact assessments here, provided the maximum rate of transmission for all exports through a border system does not exceed the authorized limit of the system (*see* Order below, Section VII, paragraph (A)). In its application, Research Power Corporation committed to complying with all reliability limits on border facilities. *See* App. at 3. The second part of the reliability inquiry is therefore satisfied by DOE regulatory oversight, in addition to NERC's reliability enforcement.

III. FINDINGS AND DECISION

A. Research Power Corporation Meets the Statutory Requirements to Export Electric Energy to Canada

[12] DOE issues Presidential permits pursuant to Executive Order 10,485, as amended by Executive Order 12,038. *See* 10 C.F.R. §§ 205.320-205.329.

[13] *See, e.g.*, *AEP Tex. Cent. Co*., Order No. PP-317, at 2-3 (Jan. 22, 2007); *Mont. Alta. Tie Ltd.*, Order No. PP-305, at 2-4 (Nov. 17, 2008).

As explained above, DOE has assessed the impact that the proposed export would have on the reliability of the United States electric power supply system. DOE has determined that the export of electric energy to Canada by Research Power Corporation, as ordered below, would not impair the sufficiency of electric power supply within the United States and would not impede or tend to impede the coordination in the public interest of facilities within the meaning of FPA § 202(e).

B. Research Power Corporation Qualifies for a NEPA Categorical Exclusion for Exports of Electric Energy

Research Power Corporation's Application qualifies for DOE's categorical exclusion for exports of electric energy under the National Environmental Policy Act of 1969, as amended (NEPA), 42 U.S.C. § 4321 *et seq*. DOE's NEPA Implementing Procedures (June 2025) set forth this categorical exclusion, codified as "B4.2," as follows:

> Export of electric energy as provided by Section 202(e) of the Federal Power Act over existing transmission lines or using transmission system changes that are themselves categorically excluded.

10 C.F.R. Part 1021, App. B, § B4.2.

DOE has determined that actions in this category do not normally have a significant effect on the human environment and that, therefore, neither an environmental assessment nor an environmental impact statement normally is required. 10 C.F.R. § 1021.102(a).

To invoke this categorical exclusion, DOE must determine that, in relevant part, "[t]here are no extraordinary circumstances related to the proposal that may affect the significance of the environmental effects of the proposal." 10 C.F.R. § 1021.102(b)(2). "Extraordinary circumstances" include "unique situations" such as "scientific controversy about the environmental effects of the proposal; uncertain effects or effects involving unique or unknown risks; and unresolved conflicts concerning alternative uses of available resources." *Id*. DOE finds that granting Research Power Corporation's request for export authorization does not present such extraordinary circumstances. Research Power Corporation seeks to deliver electricity over existing international electric transmission facilities, which fits squarely within the B4.2 categorical exclusion. For these reasons, DOE will not require more detailed NEPA review in connection with this Application.

C. Conclusion

DOE grants Research Power Corporation's request for export authorization. Research Power Corporation is authorized to export electricity to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties, subject to the limitations and conditions described in this Order. The authorization shall be effective for a five (5) year term consistent with DOE's standard term for new electricity export authorizations.

IV. DATA COLLECTION AND REPORTING REQUIREMENTS

The responsibility for the data collection and reporting under orders authorizing electricity exports to a foreign country currently rests with the U.S. Energy Information Administration (EIA) within DOE. The Applicant is instructed to follow EIA instructions in completing this data exchange. Questions regarding the data collection and reporting requirements can be directed to EIA by email at EIA4USA@eia.gov or by phone at 1-855-342-4872.

Additionally, any change to the tariff of an entity with an export authorization must be provided to DOE's Grid Deployment Office via email at *electricity.exports@hq.doe.gov*. 10 C.F.R. § 205.308(b).

V. COMPLIANCE

Obtaining a valid order from DOE authorizing the export of electricity under FPA § 202(e) is a necessary condition before engaging in the export. Failure to obtain such an order or continuing to export after the expiration of such an order may result in a denial of authorization to export in the future and subject the exporter to sanctions and penalties under the FPA. DOE expects transmitting utilities owning border facilities and entities charged with the operational control of those border facilities, such as ISOs, RTOs, or balancing authorities, to verify that companies seeking to schedule an electricity export have the requisite authority from DOE to export such energy.

DOE expects Research Power Corporation to abide by the terms and conditions established for its authority to export electric energy to Canada, as set forth below. DOE intends to monitor Research Power Corporation compliance with these terms and conditions, including the requirement in paragraph G of this Order that Research Power Corporation create and preserve full and complete records and file reports with EIA as discussed above.

A violation of any of these terms and conditions, including the failure to submit timely and accurate reports, may result in the loss of authority to export electricity and subject Research Power Corporation to any applicable sanctions and penalties under the FPA.

VI. OPEN ACCESS POLICY

An export authorization issued under FPA § 202(e) does not impose a requirement on transmitting utilities to provide service. However, DOE expects transmitting utilities that own border facilities to provide open access transmission service across the border in accordance with the principles of comparable open access and non-discrimination contained in the FPA and articulated in FERC Order No. 888 (Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, FERC Statutes and Regulations ¶ 31,036 (1996)), as amended. The actual rates, terms, and conditions of transmission service should be consistent with the non-discrimination principles of the FPA and the transmitting utility's Open-Access Transmission Tariff on file with FERC.

All recipients of export authorizations, including owners of border facilities for which Presidential permits have been issued, are required by their export authorization to conduct operations in accordance with the applicable principles of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended. Cross-border electric trade ought to be subject to the same principles of comparable open access and non-discrimination that apply to transmission in interstate commerce. *See Enron Power Mktg., Inc. v. El Paso Elec. Co.*, 77 FERC ¶ 61,013 (1996), *reh'g denied*, 83 FERC ¶ 61,213 (1998). Thus, DOE expects owners of border facilities to comply with the same principles of comparable open access and non-discrimination that apply to the domestic, interstate transmission of electricity.

VII. ORDER

Accordingly, pursuant to FPA § 202(e) and the Rules and Regulations issued thereunder (10 C.F.R. §§ 205.300-309), it is hereby ordered that Research Power Corporation is authorized to export electric energy to Canada under the following terms and conditions:

(A) The electric energy exported by Research Power Corporation pursuant to this Order may be delivered to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties in accordance with the export limits authorized by DOE.

(1) The following international transmission facilities located at the United States border with Canada are currently authorized by Presidential permit and available for open access transmission:[14, 15]

Owner	**Location**	**Voltage**	**Permit No.**[16]
Bangor Hydro-Electric Company	Baileyville, ME	345 kV	PP-89
Basin Electric Power Cooperative	Tioga, ND	230 kV	PP-64
Bonneville Power Administration (BPA)	Blaine, WA	2x 500 kV	PP-10
	Nelway, WA	230 kV	PP-36
	Nelway, WA	230 kV	PP-46
CHPE, LLC	Champlain, NY	±230 kV DC	PP-481[17]

[14] This Order authorizes the export of electricity over any "authorized international transmission facility," which is intended to include both large transmission lines and smaller distribution lines that have received a Presidential permit. However, the list in subparagraph (A)(1) of current facilities only includes transmission lines.

[15] The Applicant submitted a list identifying currently authorized transmission facilities (Attachment 1 of the Application). However, as information about some of those facilities may have changed since the Application was submitted, the table of transmission facilities in this Order may differ from the Applicant's submission to reflect those changes.

[16] These Presidential permit numbers refer to the generic DOE permit number and are intended to include any subsequent amendments to the permit authorizing the facility.

[17] Currently under construction and not yet operational as of September 2025.

Eastern Maine Electric Cooperative	Calais, ME	69 kV	PP-32
International Transmission Company	Detroit, MI	230 kV	PP-230
	Marysville, MI	230 kV	PP-230
	St. Claire, MI	230 kV	PP-230
	St. Claire, MI	345 kV	PP-230
Lake Erie Connector Transmission, LLC	Erie County, PA	320 kV	PP-412[18]
Long Sault, Inc.	Massena, NY	2x 115 kV	PP-24
Maine Electric Power Company	Houlton, ME	345 kV	PP-43
Minnesota Power, Inc.	International Falls, MN	115 kV	PP-78
Minnesota Power, Inc.	Roseau County, MN	500 kV	PP-398
Minnkota Power Cooperative	Roseau County, MN	230 kV	PP-61
Montana Alberta Tie Ltd.	Cut Bank, MT	230 kV	PP-399
NECEC Transmission LLC	Beattie Twp, ME	±320 kV	PP-438[19]
New York Power Authority	Massena, NY	765 kV	PP-56
	Massena, NY	2x 230 kV	PP-25
	Niagara Falls, NY	2x 345 kV	PP-74
	Devils Hole, NY	230 kV	PP-30
Niagara Mohawk Power Corp.	Devils Hole, NY	230 kV	PP-190
Northern States Power Company	Red River, ND	230 kV	PP-45
	Roseau County, MN	500 kV	PP-63
	Rugby, ND	230 kV	PP-231
Sea Breeze Olympic Converter LP	Port Angeles, WA	±450 kV DC	PP-299[20]
TDI New England	Alburgh, VT	±320 kV DC	PP-400[21]

[18] These transmission facilities have been authorized but not yet constructed or placed into operation.
[19] These transmission facilities have been authorized but not yet constructed or placed into operation.
[20] These transmission facilities have been authorized but not yet constructed or placed into operation.
[21] These transmission facilities have been authorized but not yet constructed or placed into operation.

Vermont Electric Power Co.	Derby Line, VT	120 kV	PP-66
Vermont Electric Transmission Co.	Norton, VT	±450 kV DC	PP-76
Vermont Transco LLC	Highgate, VT	120 kV	PP-82
Versant Power	Fort Fairfield, ME	69 kV	PP-497
	Madawaska, ME	138 kV	PP-498
	Easton, ME	7.2 kV	PP-499
	Baileyville, ME	345kV	PP-500

(2) The following are the authorized export limits for the international transmission lines listed above in subparagraph (A)(1):

(a) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on facilities authorized by Presidential Permit PP-64 (issued to Basin Electric Power Coop.) to exceed an instantaneous transmission rate of 150 megawatts (MW). The gross amount of energy that Research Power Corporation may export over the PP-64 facilities shall not exceed 900,000 megawatt-hours (MWH) during any consecutive 12-month period.

(b) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-32 (issued to Eastern Maine Electric Coop.) to exceed an instantaneous transmission rate of 15 MW. The gross amount of energy that Research Power Corporation may export over the PP-32 facilities shall not exceed 7,500 MWH annually.

(c) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-481-2 (issued to CHPE, LLC) to exceed an instantaneous transmission rate of 1,250 MW.

(d) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-230 (issued to International Transmission Company) to exceed a coincident, instantaneous transmission rate of 2.2 billion volt-amperes (2,200 MVA).

(e) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-412-1 (issued to Lake Erie Connector Transmission, LLC) to exceed an instantaneous transmission rate of 1,000 MW.

(f) Exports by Research Power Corporation made pursuant to this Order shall not cause the scheduled rate of transmission over a combination of facilities authorized by Presidential Permits PP-43 (issued to Maine Electric Power Company) and PP-500 (issued to Bangor Hydro-Electric) to exceed 550 MW.

(g) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the combination of facilities authorized by Presidential Permits PP-497 and PP-498 (issued to Versant Power) to exceed a coincident, instantaneous transmission rate of 134 MW.

(h) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-78-1 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 100 MW. Exports by Research Power Corporation may cause total exports on the PP-78-1 facilities to exceed 100 MW only when total exports between the Mid-Continent Area Power Pool (MAPP) and Manitoba Hydro are below maximum transfer limits and/or whenever operating conditions within the MAPP system permit exports on the PP-78-1 facilities above the 100-MW level without violating established MAPP reliability criteria. However, under no circumstances shall exports by Research Power Corporation cause the total exports on the PP-78-1 facilities to exceed 150 MW.

(i) Exports made by Research Power Corporation pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-398 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 750 MW.

(j) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on a combination of the international transmission lines authorized by Presidential Permits PP-45 and PP-63 (issued to Northern States Power Company), PP-61 (issued to Minnkota Power), and PP-231 (issued to Northern States Power Company, d/b/a Excel Energy Inc. (Xcel)), to exceed an instantaneous transmission rate of 700 MW on a firm basis and 1,050 MW on a non-firm basis.

(k) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-66 (issued to Vermont Electric Power Co.) to exceed an instantaneous transmission rate of 50 MW. The gross amount of energy that Research Power Corporation may export over the PP-66 facilities shall not exceed 50,000 MWH annually.

(l) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-56 (issued to NYPA) to exceed an instantaneous transmission rate of 1,000 MW.

(m) Exports by Research Power Corporation made pursuant to this Order shall not cause: (a) the total exports on the facilities authorized by Presidential Permits PP-25, PP-30, PP-74 (issued to NYPA), and PP-190 (issued to Niagara Mohawk Power Corp.) to exceed a combined instantaneous transmission rate of 1,650

MW; and (b) the total exports on the 115-kV facilities authorized by Presidential Permit PP-24 (issued to Long Sault, Inc.) to exceed an instantaneous transmission rate of 100 MW. In addition, the gross amount of energy that Research Power Corporation may export over the PP-24 facilities shall not exceed 300,000 MWH annually.

(n) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on the two 500-kV lines authorized by Presidential Permit PP-10, the 230-kV line authorized by Presidential Permit PP-36, and the 230-kV line authorized by Presidential Permit PP-46 (issued to BPA) to exceed the following limits:

Condition	PP-36 & PP-46 Limit	PP-10 Limit	Total Export Limit
All lines in service	400 MW	1500 MW	1900 MW
1-500 kV line out	400 MW	300 MW	700 MW
2-500 kV lines out	400 MW	0 MW	400 MW
1-230 kV line out	400 MW	1500 MW	1900 MW
2-230 kV line out	0 MW	1500 MW	1500 MW

(o) Exports by Research Power Corporation made pursuant to this Order shall not cause a violation of the following conditions as they apply to exports over the facilities authorized by Presidential Permit PP-76-1, as amended (issued to the Vermont Electric Transmission Company):

Exports Through	NEPOOL Load Condition	Export Limit
Comerford converter	Summer, Heavy	650 MW
Comerford converter	Winter, Heavy	660 MW
Comerford converter	Summer, Light	690 MW
Comerford converter	Winter, Light	690 MW
Comerford & Sandy Pond converters	All	2,000 MW

(p) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-399 (issued to Montana Alberta Tie Ltd.) shall not exceed an instantaneous transmission rate of 300 MW.

(q) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-438 (issued to NECEC Transmission LLC) shall not exceed an instantaneous transmission rate of 1,200 MW.

(r) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-299 (issued to Sea Breeze Olympic Converter LP) shall not exceed an instantaneous transmission rate of 550 MW.

(s) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-400 (issued to TDI-New England) to exceed an instantaneous transmission rate of 1,000 MW.

(t) Exports by Research Power Corporation made pursuant to this Order shall neither cause the total exports on the facilities authorized by Presidential Permit PP-82-6 (issued to Vermont Transco LLC) to exceed an instantaneous transmission rate of 250 MW.

(B) Changes by DOE to the export limits in other orders shall result in a concomitant change to the export limits contained in subparagraph (A)(2) of this Order. Changes to the export limits contained in subparagraphs (A)(2)(l), (m), and (n) will be made by DOE after submission of appropriate information demonstrating a change in the transmission transfer capability between the electric systems in New York State and Ontario and New York State and Quebec, and between BPA and BC Hydro or BPA and West Kootenay Power. Notice of these changes will be provided to Research Power Corporation.

(C) Research Power Corporation shall obtain any and all other Federal and state regulatory approvals required to execute any power exports to Canada. The scheduling and delivery of electricity exports to Canada shall comply with all reliability criteria, standards, and guidelines of NERC, reliability coordinators, Regional Entities, RTOs, ISOs or balancing authorities, or their successors, as appropriate, on such terms as expressed therein, and as such criteria, standards, and guidelines may be amended from time to time.

(D) Exports made pursuant to this authorization shall be conducted in accordance with the applicable provisions of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended.

(E) The authorization herein granted may be modified from time to time or terminated by further order of DOE. In no event shall such authorization to export over a particular transmission facility identified in subparagraphs (A)(1) and (2) extend beyond the date of termination of the Presidential permit or treaty authorizing such facility.

(F) This authorization shall be without prejudice to the authority of any state or state regulatory commission for the exercise of any lawful authority vested in such state or state regulatory commission.

(G) Research Power Corporation shall make and preserve full and complete records with respect to the electric energy transactions between the United States and Canada. Research Power Corporation shall collect and submit the data to EIA as required by and in accordance with the procedures of Form EIA-111, "Quarterly Electricity Imports and Exports Report," and all successor forms.

(H) In accordance with 10 C.F.R. § 205.305, this export authorization is not transferable or assignable, except in the event of involuntary transfer by operation of law. Provided written notice of the involuntary transfer is given to DOE within 30 days, this authorization shall remain in effect temporarily. The authorization shall terminate unless an application for a new export authorization has been received by DOE within 60 days of the involuntary transfer. Upon receipt by DOE of such an application, this existing authorization shall continue in effect pending a decision on the new application. In the event of a proposed voluntary transfer of this authority to export electricity, the transferee and the transferor shall file a joint application for a new export authorization, together with a statement of the reasons for the transfer.

(I) Nothing in this Order is intended to prevent the transmission system operator from being able to reduce or suspend the exports authorized herein, as necessary and appropriate, whenever a continuation of those exports would cause or exacerbate a transmission operating problem or would negatively impact the security or reliability of the transmission system.

(J) Research Power Corporation has a continuing obligation to give DOE written notification as soon as practicable of any prospective or actual changes of a substantive nature in the circumstances upon which this Order was based, including but not limited to changes in authorized entity contact information or NERC compliance registry status.

(K) This authorization shall be effective as of October 21, 2025 and shall remain in effect for a period of five (5) years from that date. Application for renewal of this authorization may be filed within six (6) months prior to its expiration. Failure to provide DOE with at least one hundred and twenty (120) days to process a renewal application and provide adequate opportunity for public comment may result in a gap in Research Power Corporation's authority to export electricity.

Issued in Washington, D.C., on October 21, 2025.

Chris Wright

Chris Wright
Secretary of Energy
U.S. Department of Energy

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	Order No. 202-26-18

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

Exhibit 2-63:
Gridforce 2019 Audit Report

NCR ID:	**NCR11393**		
Registered Entity Name:	**Gridforce Energy Management, LLC**		
Registered Entity Acronym:	**GRID**		
Reliability Standards Scope:	**Operations & Planning (FERC Order 693) Standards**		
Compliance Monitoring Process:	**Compliance Audit**		
Distribution:	**Public Version. Confidential Information Has Been Removed, Including Privileged and Critical Energy Infrastructure Information.**		
Regional Entity:	**Western Electricity Coordinating Council (WECC)**		
Date of Opening Presentation:	**September 24, 2019**	Date of Closing Presentation:	**September 26, 2019**
Date of Report:	**December 20, 2019**	IP Year:	**2019**
Potential Noncompliance:	**None (zero)**		
Jurisdiction:	**United States**		

Table of Contents

Executive Summary

WECC conducted an Operations & Planning (FERC Order 693) Standards Compliance Audit of Gridforce Energy Management, LLC (GRID), NCR ID NCR11393 from September 24, 2019 to September 26, 2019.

At the time of the Compliance Audit, GRID was registered for the function of Balancing Authority (BA).

The Reliability Coordinator (RC) for GRID is Peak Reliability (PEAK). The Transmission Operators (TOP), Planning Authorities (PA), Transmission Planners (TP), and Resource Planners (RP) for GRID are Bonneville Power Administration (BPA), Public Service Company of New Mexico (PNM), and Salt River Project Agricultural Improvement and Power District (SRP).

The Compliance Audit team (team) evaluated GRID for compliance with Seven (7) Operations and Planning requirements for the 2019 Electric Reliability Organization (ERO) Enterprise Compliance Monitoring and Enforcement Program (CMEP). The team assessed compliance with the NERC Reliability Standards for the period of June 29, 2016 to June 17, 2019.

GRID submitted evidence for the team's evaluation of compliance with requirements. The team reviewed and evaluated all evidence provided to assess compliance with Reliability Standards applicable to GRID at this time.

Based on the evidence provided, no findings were noted for the Reliability Standards and applicable Requirements in scope for this engagement.

There were no open Mitigation Plans; therefore, none were reviewed by the team.

The WECC Compliance Audit team lead certifies that the team adhered to all applicable requirements of the NERC Rules of Procedure (ROP) and Compliance Monitoring and Enforcement Program (CMEP).[1]

Compliance Audit Process

The Compliance Audit process steps are detailed in the NERC ROP. The CMEP generally conforms to the United States Government Auditing Standards and other generally accepted audit practices.

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[1]This statement replaces the Regional Entity Self-Certification process.

Objectives

All registered entities are subject to compliance assessments with all Reliability Standards applicable to the functions for which the registered entity is registered[2] in the Region(s) performing the assessment. The Compliance Audit objectives are designed to:

- Provide reasonable assurance of compliance to the identified applicable Reliability Standards;
- Review compliance with applicable NERC Reliability Standards identified for 2019 ERO Enterprise CMEP;
- Review evidence of self-reported violations and previous self-certifications;

Scope

The scope of this Compliance Audit considered the NERC Reliability Standards from 2019 ERO Enterprise CMEP Implementation Plan and Inherent Risk Assessment (IRA) of GRID completed by WECC. In addition, the scope of the Compliance Audit included a review of Mitigation Plans or Remedial Action Directives that were open during the Compliance Audit.

The Reliability Standards and Requirements in-scope for this Compliance Audit are illustrated in **Table 2** Compliance Audit Scope.:

Table 2: Compliance Audit Scope	
Standards	**Requirement(s)**
COM-001-3	R9
COM-002-4	R4
COM-002-4	R6
EOP-008-2	R1
EOP-008-2	R6
EOP-011-1	R2
TOP-010-1(i)	R4

The team did not expand the scope of the Compliance Audit beyond what was stated in the notification package.

Controls

The team reviewed GRID's related internal controls associated with some of the NERC Reliability Standards in scope.

Confidentiality and Conflict of Interest

[2]NERC ROP, Appendix 4C, Section 3.1, Compliance Audits.

Confidentiality and conflict of interest of the team are governed under the Regional Delegation Agreements with NERC, and Section 1500 of the NERC ROP[3] . GRID was informed of Western Electricity Coordinating Council (WECC)'s obligations and responsibilities under the agreement and procedures. The work history for each team member was provided to GRID, which was given an opportunity to object to a team member's participation on the basis of a possible conflict of interest or the existence of other circumstances that could interfere with a team member's impartial performance of duties. GRID had not submitted any objections by the stated objection due date based on the ROP and accepted the team member participants without objection. There were no denials or access limitations placed upon this team by GRID.

Methodology

The ERO Compliance Monitoring and Enforcement Manual (Manual)[4] documents the ERO Enterprise's current approaches used to assess a registered entity's compliance with the NERC Reliability Standards. The ERO Enterprise uses, "to the extent possible, the Generally Accepted Auditing Standards (GAAS), the Generally Accepted Government Auditing Standards (GAGAS), and standards sanctioned by the Institute of Internal Auditors, as guidance for performing activities under the Compliance Monitoring and Enforcement Program (CMEP)."[5] While the ERO Enterprise does not necessarily perform compliance monitoring activities that must be in accordance with these standards recognized in the United States, the ERO Enterprise uses these standards as framework to conduct compliance monitoring activities under the CMEP, and recognizes that these standards provide information used in oversight, accountability, transparency, and improvements in ERO Enterprise operations.

The Western Electricity Coordinating Council (WECC) provided GRID with a Compliance Audit notification package to commence the Compliance Audit. GRID provided evidence at the time requested, or as agreed upon, by Western Electricity Coordinating Council (WECC). The team reviewed the evidence submitted by GRID and assessed compliance with the requirements of the applicable Reliability Standards. Additional evidence could be submitted until the agreed-upon deadline prior to the exit briefing. After that date, only data or information that was relevant to the content of the report or its finding could be submitted with the agreement of the team lead.

The team reviewed documentation provided by GRID and requested additional evidence and sought clarification from subject matter experts during the Compliance Audit. The evidence submitted in the form of policies, procedures, emails, logs, studies, data sheets, etc. were validated, substantiated, and

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[3] See NERC ROP

[4] http://www.nerc.com/pa/comp/Pages/ERO-Enterprise-Compliance-Auditor-Manual.aspx

[5] NERC ROP, Section 1207 and 126 FERC 61,038, Paragraph 3

cross-checked for accuracy as appropriate. Where sampling is applicable to a requirement, the sample set was determined by a statistical methodology, along with professional judgment as mentioned in the Manual.

The findings were based on the facts and documentation reviewed, the team's knowledge of the Bulk Electric System (BES), the NERC Reliability Standards, and professional judgment. All findings were developed based upon the consensus of the team.

Company Profile

Gridforce Energy Management, LLC is a holding company providing Balancing Authority Services under multiple NERC-registered Balancing Authorities inclusive of the NERC-registered entity GRID. GRID as a generation-only Balancing Authority (BA) balances approximately 3,155 MW of generation. GRID balances generation amounts indicated per the following NERC Registered Entity generation entities and generation resource amounts located within the Western Interconnection:

- Calpine Hermiston (NCR00060) (615 MW)
- Perennial Hermiston (NCR5181) (240 MW)
- Centralia Generation Plant (NCR05533) (1,400 MW)
- Mesquite Power (NCR05235) (600 MW)
- Broadview Wind Project (NCR11714) (300 MW)

Compliance Audit Findings

Based on the results of this Compliance Audit, no findings were noted for the Reliability Standards and applicable Requirements in scope for this engagement.

Compliance Culture

GRID's compliance culture was not formally reviewed by the team as part of the compliance audit. Assessment of GRID's internal compliance program will be reviewed by WECC Enforcement on an as-needed basis.

WECC Contact Information

Any questions regarding this Compliance Audit report can be directed to:

WECC

155 North 400 West, Suite 200
Salt Lake City, UT 84103

On behalf of WECC, this report was prepared and reviewed by:

Compliance Audit Team Lead	Date
Senior Compliance Auditor, Operations and Planning	November 4, 2019
Management Rep	**Date**
Compliance Monitoring Manager, Operations and Planning	November 4, 2019

Appendix 1: Compliance Audit Participants

Appendix Table 1: Compliance Audit Team and Appendix Table 2: GRID Participants list all personnel from the team and GRID who were directly involved during the meetings and interviews.

Appendix Table 1: Compliance Audit Team		
Role	**Title**	**Entity**
Audit Team Lead	Senior Compliance Auditor	WECC
Team Member	WECC Consultant	WECC
Team Member	Senior Compliance Auditor	WECC
Team Member	Compliance Auditor	WECC
Team Member	Compliance Program Coordinator	WECC

Appendix Table 2: GRID Participants	
Title	**Entity**
President	Gridforce
Director	Gridforce
Vice President	Gridforce
Security Engineer	Gridforce
System Operator	Gridforce
EMS Engineer 3	Gridforce

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-26-18

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

Exhibit 2-64:
Gridforce 2022 Audit Report

NCR ID:	**NCR11393**		
Registered Entity Name:	**Gridforce Energy Management, LLC**		
Registered Entity Acronym:	**Gridforce**		
Reliability Standards Scope:	**Operations & Planning (FERC Order 693) Standards**		
Compliance Monitoring Process:	**Compliance Audit**		
Distribution:	**Public Version. Confidential Information Has Been Removed, Including Privileged and Critical Energy Infrastructure Information.**		
Regional Entity:	**Western Electricity Coordinating Council (WECC)**		
Date of Opening Presentation:	**July 25, 2022**	Date of Closing Presentation:	**August 5, 2022**
Date of Report:	**November 30, 2022**	IP Year:	**2022**
Potential Noncompliance:	**None (zero)**		
Jurisdiction:	**United States**		

Table of Contents

Executive Summary

WECC conducted an Operations & Planning (FERC Order 693) Standards Compliance Audit of Gridforce Energy Management, LLC (Gridforce), NCR ID NCR11393 from July 25, 2022 to August 5, 2022.

At the time of the Compliance Audit, Gridforce was registered for the function of Balancing Authority (BA).

The Reliability Coordinator (RC) for Gridforce is Southwest Power Pool, Inc.; the Transmission Operator (TOP) is Bonneville Power Administration.

The Compliance Audit team (team) evaluated Gridforce for compliance with eight (8) Operations and Planning requirements for the 2022 Electric Reliability Organization (ERO) Enterprise Compliance Monitoring and Enforcement Program (CMEP). The team assessed compliance with the NERC Reliability Standards for the period of June 18, 2019, to March 25, 2022.

Gridforce submitted evidence for the team's evaluation of compliance with requirements. The team reviewed and evaluated all evidence provided to assess compliance with Reliability Standards applicable to Gridforce at this time.

Based on the evidence provided, no findings were noted for the Reliability Standards and applicable Requirements in scope for this engagement.

The Audit team did not identify any areas of concern[1] or recommendations.

There were open Mitigation Plans; therefore, portions were reviewed by the team.

The WECC Compliance Audit team lead certifies that the team adhered to all applicable requirements of the NERC Rules of Procedure (ROP) and Compliance Monitoring and Enforcement Program (CMEP).[2]

Compliance Audit Process

The Compliance Audit process steps are detailed in the NERC ROP. The CMEP generally conforms to the United States Government Auditing Standards and other generally accepted audit practices.

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[1]Per FERC Guidance Order on Compliance Audits Conducted by the Electric Reliability Organization and Regional Entities, dated January 15, 2009.

[2]This statement replaces the Regional Entity Self-Certification process.

Objectives

All registered entities are subject to compliance assessments with all Reliability Standards applicable to the functions for which the registered entity is registered[3] in the Region(s) performing the assessment. The Compliance Audit objectives are designed to:

- Provide reasonable assurance of compliance to the identified applicable Reliability Standards;
- Review compliance with applicable NERC Reliability Standards identified for 2022 ERO Enterprise CMEP;
- Review evidence of self-reported violations and previous self-certifications;
- Review Gridforce's internal compliance program and controls;
- Review the status of open Mitigation Plans.

Scope

The scope of this Compliance Audit considered the NERC Reliability Standards from the 2022 ERO Enterprise CMEP Implementation Plan, Inherent Risk Assessment (IRA) of Gridforce completed by WECC. In addition, the scope of the Compliance Audit included a review of Mitigation Plans or Remedial Action Directives that were open during the Compliance Audit.

The Reliability Standards and Requirements in-scope for this Compliance Audit are illustrated in **Table 2** Compliance Audit Scope.:

Table 2: Compliance Audit Scope		
Registered Function	**Standards**	**Requirement(s)**
BA	EOP-008-2	R2.
BA	EOP-008-2	R5.
BA	EOP-008-2	R6.
BA	EOP-008-2	R7.
BA	EOP-011-1	R2.
BA	INT-006-5	R1.
BA	TOP-001-5	R23.
BA	TOP-001-5	R24.

The team did not expand or reduce the scope of the Compliance Audit beyond what was stated in the notification package.

[3]NERC ROP, Appendix 4C, Section 3.1, Compliance Audits.

Internal Compliance Program

Within the scope of the Compliance Audit, Gridforce's compliance program was not reviewed.

Controls

The team reviewed Gridforce's related internal controls associated with NERC Reliability Standards in scope.

Confidentiality and Conflict of Interest

Confidentiality and conflict of interest of the team are governed under the Regional Delegation Agreements with NERC, and Section 1500 of the NERC ROP. [4] Gridforce was informed of WECC's obligations and responsibilities under the agreement and procedures. The work history for each team member was provided to Gridforce, which was given an opportunity to object to a team member's participation on the basis of a possible conflict of interest or the existence of other circumstances that could interfere with a team member's impartial performance of duties. Gridforce had not submitted any objections by the stated objection due date based on the ROP and accepted the team member participants without objection. There were no denials or access limitations placed upon this team by Gridforce.

Methodology

The ERO Compliance Monitoring and Enforcement Manual (Manual)[5] documents the ERO Enterprise's current approaches used to assess a registered entity's compliance with the NERC Reliability Standards. The ERO Enterprise uses, "to the extent possible, the Generally Accepted Auditing Standards (GAAS), the Generally Accepted Government Auditing Standards (GAGAS), and standards sanctioned by the Institute of Internal Auditors, as guidance for performing activities under the Compliance Monitoring and Enforcement Program (CMEP)."[6] While the ERO Enterprise does not necessarily perform compliance monitoring activities that must be in accordance with these standards recognized in the United States, the ERO Enterprise uses these standards as framework to conduct compliance monitoring activities under the CMEP, and recognizes that these standards provide information used in oversight, accountability, transparency, and improvements in ERO Enterprise operations.

WECC provided Gridforce with a Compliance Audit notification package to commence the Compliance Audit. Gridforce provided evidence at the time requested, or as agreed upon, by WECC.

[4] See NERC ROP

[5] https://www.nerc.com/pa/comp/CAOneStopShop/ERO_Enterprise_Compliance%20Monitoring%20and%20Enforcement%20Manual_v5.0.pdf

[6] NERC ROP, Section 1207 and 126 FERC 61,038, Paragraph 3

The team reviewed the evidence submitted by Gridforce and assessed compliance with the requirements of the applicable Reliability Standards. Additional evidence could be submitted until the agreed-upon deadline prior to the exit briefing. After that date, only data or information that was relevant to the content of the report or its finding could be submitted with the agreement of the team lead.

The team reviewed documentation provided by Gridforce and requested additional evidence and sought clarification from subject matter experts during the Compliance Audit. The evidence submitted in the form of policies, procedures, emails, logs, studies, data sheets, etc. were validated, substantiated, and cross-checked for accuracy as appropriate. Where sampling is applicable to a requirement, the sample set was determined by a statistical methodology, along with professional judgment as mentioned in the Manual.

The findings were based on the facts and documentation reviewed, the team's knowledge of the Bulk Electric System (BES), the NERC Reliability Standards, and professional judgment. All findings were developed based upon the consensus of the team.

Company Profile

Gridforce Energy Management, LLC, (GEM) founded in 2001, based in Houston, Texas and was acquired by NAES Corporation (NAES) in July 2017.

The NAES Corporation was founded in 1980, is based in Issaquah, Washington, is a wholly-owned subsidiary of ITOCHU Corporation. NAES is an independent services company dedicated to optimizing the performance of energy facilities across the power generation landscape.

The NAES team consists of ~4,000 colleagues, possessing a national footprint, with experience in operations, maintenance, construction, engineering and technical support, in order to support client needs by constructing, operating and maintaining traditional and renewable resources.

NAES is currently responsible and/or supporting more than 1,360 facilities producing, ~100 GW of generation nationwide.

Compliance Audit Findings

Based on the results of this Compliance Audit, no findings were noted for the Reliability Standards and applicable Requirements in scope for this engagement.

Compliance Culture

Gridforce's compliance culture was not formally reviewed by the team as part of the compliance audit. Assessment of Gridforce's internal compliance program will be reviewed by WECC Enforcement on an as-needed basis.

WECC Contact Information

Any questions regarding this Compliance Audit report can be directed to:

WECC
155 North 400 West, Suite 200
Salt Lake City, UT 84103

On behalf of WECC, this report was prepared and reviewed by:

Compliance Audit Team Lead	Date
Compliance Auditor, Operations & Planning	September 2, 2022
Management Rep	**Date**
Manager, Entity Monitoring, Operations & Planning	September 2, 2022

Appendix 1: Compliance Audit Participants

Appendix Table 1: Compliance Audit Team and Appendix Table 2: Gridforce Participants list all personnel from the team and Gridforce who were directly involved during the meetings and interviews.

Appendix Table 1: Compliance Audit Team		
Role	**Title**	**Entity**
Compliance Audit Team Lead	Compliance Auditor, Operations and Planning	WECC
Team Member	Senior Compliance Auditor, Operations and Planning	WECC
Team Member	Senior Compliance Auditor, Operations and Planning	WECC
Team Member	Compliance Auditor, Operations and Planning	WECC
Team Member	Compliance Auditor, Operations and Planning	WECC
Team Member	Compliance Auditor, Operations and Planning	WECC
Team Member	Compliance Program Coordinator	WECC
Observer	Director of Entity Monitoring	WECC
Observer	Director, Entity Risk Assessment & Registration	WECC
Observer	Manager, Entity Monitoring, Operations & Planning	WECC
Observer	Internal Controls and Compliance Analyst	WECC

Appendix Table 2: Gridforce Participants	
Title	**Entity**
Director of Reliability Compliance	Gridforce
Director of CIP Compliance	Gridforce
Operations Engineer at BUCC	Gridforce
President	Gridforce
Director of Operations	Gridforce
System Operator at PCC	Gridforce
System Operator at the BUCC	Gridforce
Director of Applications and Infrastructure	Gridforce

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

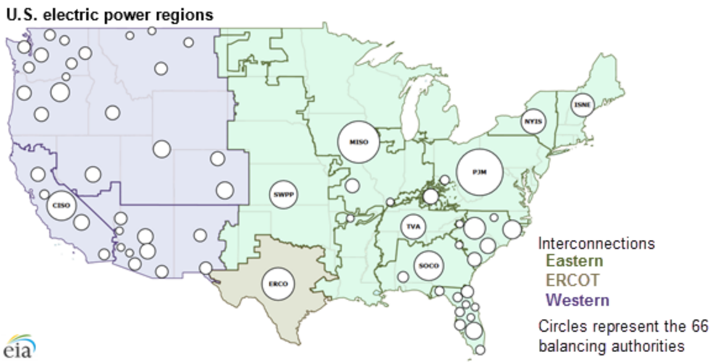
Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-26-18

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

Exhibit 2-65:
EIA Explainer on Balancing Authorities

July 20, 2016

U.S. electric system is made up of interconnections and balancing authorities



Source: U.S. Energy Information Administration
Note: The locations of the electric systems are illustrative and are not geographically accurate. The sizes of the circles are roughly indicative of electric system size.

Electricity generated at power plants moves through a complex network of electricity substations, power lines, and distribution transformers before it reaches customers. In the United States, the power system consists of more than 7,300 power plants, nearly 160,000 miles of high-voltage power lines, and millions of low-voltage power lines and distribution transformers, which connect 145 million customers.

Local electricity grids are interconnected to form larger networks for reliability and commercial purposes. At the highest level, the United States power system in the Lower 48 states is made up of three main interconnections, which operate largely independently from each other with limited transfers of power between them.

- The Eastern Interconnection encompasses the area east of the Rocky Mountains and a portion of northern Texas. The Eastern Interconnection consists of 36 balancing authorities: 31 in the United States and 5 in Canada.
- The Western Interconnection encompasses the area from the Rockies west and consists of 37 balancing authorities: 34 in the United States, 2 in Canada, and 1 in Mexico.
- The Electric Reliability Council of Texas (ERCOT) covers most, but not all, of Texas and consists of a single balancing authority.

The network structure of the interconnections helps maintain the reliability of the power system by providing multiple routes for power to flow and by allowing generators to supply electricity to many load centers. This redundancy helps prevent transmission line or power plant failures from causing interruptions in service.

These interconnections describe the physical system of the grid. The actual operation of the electric system is managed by entities called balancing authorities. Most, but not all, balancing authorities are electric utilities that have taken on the balancing responsibilities for a specific portion of the power system. All of the regional transmission organizations in the United States also function as balancing authorities. ERCOT is unique in that the balancing authority, interconnection, and the regional transmission organization are all the same entity and physical system.

A balancing authority ensures, in real time, that power system demand and supply are finely balanced. This balance is needed to maintain the safe and reliable operation of the power system. If demand and supply fall out of balance, local or even wide-area blackouts can result.

Balancing authorities maintain appropriate operating conditions for the electric system by ensuring that a sufficient supply of electricity is available to serve expected demand, which includes managing transfers of electricity with other balancing authorities. Balancing authorities are responsible for maintaining operating conditions under mandatory reliability standards issued by the North American Electric Reliability Corporation and approved by the U.S. Federal Energy Regulatory Commission and, in Canada, by Canadian regulators. These operators monitor the grid to identify potential problems before a situation becomes critical.

Principal contributor: Sara Hoff

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-26-18

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

Exhibit 2-66:
Bonneville's Typical Balancing Authority Milestones

LOCAL NEWS

Oregon lawmakers advance one-year moratorium on tax breaks for data centers

On Monday, an economic incentives bill advanced out of committee with an amendment that would pause tax breaks for new data centers.

Author: **Alma McCarty (KGW)**
Published: **11:32 PM PST March 2, 2026**
Updated: **5:18 AM PST March 3, 2026**

SALEM, Oregon — In the final week of Oregon's legislative short session, lawmakers in Salem discussed regulating data centers — specifically, placing a one-year moratorium on certain tax breaks.

Governor Tina Kotek has been looking to expand the state's enterprise zone program, which is intended to grow Oregon companies and attract new ones. Businesses that locate or expand within designated zones can qualify for property tax exemptions on new investments if they meet eligibility requirements.

However, some advocates argue that extending incentives to data centers may not be sustainable long term.

“Data centers have been around for a while,” said Kelly Campbell, policy director for Columbia Riverkeeper. “Data centers are getting bigger and bigger. Some of these new AI hyperscale data centers are exponentially bigger than those tiny ones. They’re really just using a lot of energy, a lot of water.”

Last week, Columbia Riverkeeper released a report examining data centers operating or planned along the Columbia River in Oregon and Washington.

“I think the question becomes, do we want to stick to our climate goals of getting to 100% renewable? Or do we want to have these big, mega data centers owned by big tech companies — some of the wealthiest corporations in the world — getting to use whatever energy they want? We would say, no, that’s not OK,” Campbell said.

On Monday, lawmakers amended an economic incentives bill to block new data centers from qualifying for certain tax breaks for one year.

“I think this moratorium is a pretty short pause to give the advisory council time and space to do their work,” said Rep. Nancy Nathanson, D-Eugene, during a subcommittee meeting Monday morning.

The Data Center Advisory Committee, convened by Kotek, held its first meeting Friday. The group’s goal is to develop policy recommendations addressing the rapid growth of data centers.

"There are some businesses that will need them, but freestanding data centers, the way we've been growing in the state, is not sustainable," the Governor told reporters during a press conference last week.

On Monday, her office sent KGW a statement regarding the moratorium:

"The moratorium will address immediate concerns and also allow for the Governor’s Data Center Advisory Committee to develop recommendations to strategically pursue economic development opportunities while ensuring utility costs, infrastructure investments, and environmental impacts remain sustainable and equitable for all residents."

Supporters of data center growth, particularly in rural communities, also spoke during work sessions.

“This moratorium will have a disparate impact on communities east of the Cascades — communities like Prineville, Hermiston and Redmond that have leveraged enterprise zones and data centers to bring hundreds of living-wage jobs to their communities,” said Alexandra Ring, a lobbyist for the League of Oregon Cities.

“While data centers may be seen as a nuisance or inconvenient in Washington County, they are not in Crook County. They are not in Morrow County, in Umatilla County,” said Sen. Mark McLane, who represents several Eastern Oregon counties, including Baker, Crook, Grant and Harney.

Even if the House and Senate ultimately approve the moratorium, it would apply only to new data centers — not those that already receive tax breaks or projects currently underway.

Related Articles

'I don't see this as getting better': Data centers fuel concern over water, energy use, air pollution

Oregon governor convenes group to weigh the rapid growth of data centers

Oregon bill could open 1,700 acres near Hillsboro for industrial use. Will it include data centers?

Mother of woman missing in the Bahamas details alleged past abuse

KGW

Tips for spotting the Artemis II astronauts as they splash down off San Diego's coast Friday

KGW

LOADING NEXT ARTICLE...

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

Exhibit 2-67:
Email Correspondence with E3

From:	Brad Cebulko
To:	Arne Olson; Fred Heutte
Cc:	Laura Burford; Michael Lenoff; Erik Olson; Edward Burgess
Subject:	Re: E3 NW RA study and Centralia
Date:	Friday, January 9, 2026 6:57:25 PM

External Sender

Thank you, Arne.

____

Brad Cebulko
m: 317.519.3165

From: Arne Olson <arne@ethree.com>
Sent: Friday, January 9, 2026 3:43 PM
To: Brad Cebulko <bcebulko@currentenergy.group>; Fred Heutte <fred@nwenergy.org>
Cc: Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mlenoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>; Edward Burgess <eburgess@currentenergy.group>
Subject: Re: E3 NW RA study and Centralia

Yes everything that I didn't comment on is correct

Sent from my Verizon, Samsung Galaxy smartphone
Get Outlook for Android

From: Brad Cebulko <bcebulko@currentenergy.group>
Sent: Friday, January 9, 2026 3:35:46 PM
To: Arne Olson <arne@ethree.com>; Fred Heutte <fred@nwenergy.org>
Cc: Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mlenoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>; Edward Burgess <eburgess@currentenergy.group>
Subject: Re: E3 NW RA study and Centralia

Arne,

I really appreciate the response as well as the data. Thank you. I have one final point of clarification. I understand your response as confirming the accuracy of our summary, subject to the qualifications and information you provided. Please let me know if that understanding is incorrect.

Have a great weekend.

____

Brad Cebulko
m: 317.519.3165

From: Arne Olson <arne@ethree.com>

Sent: Thursday, January 8, 2026 7:26 PM
To: Brad Cebulko <bcebulko@currentenergy.group>; Fred Heutte <fred@nwenergy.org>
Cc: Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mlenoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>; Edward Burgess <eburgess@currentenergy.group>
Subject: RE: E3 NW RA study and Centralia

Hi Brad,

Thanks for this summary. I have placed some answers below in red. Also please see the attached spreadsheet with the data that was requested.

Please let me know if I can answer any other questions for you.

Best,

Arne

From: Brad Cebulko <bcebulko@currentenergy.group>
Sent: Friday, January 2, 2026 12:22 PM
To: Arne Olson <arne@ethree.com>; Fred Heutte <fred@nwenergy.org>
Cc: Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mlenoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>; Edward Burgess <eburgess@currentenergy.group>
Subject: Re: E3 NW RA study and Centralia

Arne,

Thank you again for speaking with us on Wednesday, December 31. We appreciate you taking the time to discuss your September 2025 presentation on resource adequacy to the Washington Utilities and Transportation Commission and the Washington Department of Commerce. We also appreciate your efforts to locate and share information on Canadian entitlements, the list of in-development resources, and achieved LOLE values. Thank you for your assistance. My understanding is that your anticipated timing works, as the deadline for making use of the materials would be early the following week.

To confirm the accuracy of our notes from the Wednesday call, my colleagues and I have summarized our understanding below. Would you please let us know if the notes below are accurate and if any modifications to the below are appropriate? If possible, we'd be happy to receive this response in advance of the other materials, but also understand your schedule may get in the way.

- The “Greater Northwest” region evaluated in the presentation includes all of the traditional NW Power Act Northwest (Washington, Oregon, Idaho and western Montana) plus all of NorthWestern Energy and PAC-East.
- Slide 10 of the presentation is based on the following inputs:

- Each year shown in the table is a water year beginning October 1. So, for instance, “2026” refers to the year from October 1, 2025 through September 30, 2026.
- The “peak load” used to calculate “Total Resource Need” was developed by E3’s own load forecast. To forecast data center demand, including whether data centers will reduce load at times of peak demand, E3 used figures from utilities’ integrated resource plans.
- The “planning reserve margin” used to calculate “Total Resource Need” was calculated to achieve a loss of load expectation of one event-day per decade (i.e., the 1-in-10 LOLE standard). E3 used its own loss-of-load expectation model to calculate the planning reserve margin.
- The “Existing Portfolio w/ Retirements” assigns value to individual resources based on E3’s own set of capacity accreditation values that were developed using E3’s calculations of resource types’ marginal effective load carrying capacity.
- E3’s August whitepaper explains E3’s accreditation approach.
- Centralia is modeled as retired for all study years. In other words, the study attributes 0 MW to Centralia and does not model the proposed coal-to-gas conversion of Centralia scheduled to be completed in 2028.
- The “firm imports” of 3,750 MW each year is calculated by looking to the 2,500 MW figure that the Northwest Power and Conservation Council uses for a smaller region than the region E3 studies for the presentation. E3 added to the 2,500 MW figure to account for the larger region. E3 was intentionally conservative in setting the 3,750 MW figure. The 3,750 MW figure is not intended to represent the maximum import capability of the region E3 studied.
- The quantum of “in-development” Firm, Wind, Solar, and Battery resources are sourced from WECC’s Anchor Data Set, after accreditation using E3’s calculations of resource types’ effective load carrying capacity. The quantum of “in-development” resources does not include planned resources in utilities’ integrated resource plans shown on slide 21. To confirm whether the “in-development” resources are in service, one can investigate the status of resources shown in the WECC Anchor Data Set, including by reference to press releases.

* With regard to the “Reliability Positions” shown on slide 10:
    - The “Surplus” or “Shortfall” does not include the “in-development” resources. So, for instance, including the “in-development” resources for 2026 improves the calculated Reliability Position from a shortfall of 1,321 MW to a shortfall of 380 MW.

- Any electric system will have some level of resource adequacy risk. The "Surplus" or "Shortfall" shows whether the region has more or fewer resources needed to achieve, in E3's model, the target risk threshold of a loss of load expectation of one event-day in ten years. A shortfall indicates that the region has higher risk of loss of load than the one event-day in ten years standard. A surplus indicates that the region has lower risk of loss of load than the one event-day in ten years standard.
- The "Surplus" or "Shortfall" does not show whether the region has insufficient resources to meet forecasted peak load.

THE 'SURPLUS' OR 'SHORTFALL' SHOWS WHETHER THE REGION HAS SUFFICIENT RESOURES TO MEET FORECASTED PEAK LOAD PLUS THE PLANNING RESERVE MARGIN NEEDED TO ACHIEVE THE 0.1 LOLE RESOURCE ADEQUACY STANDARD.

- For 2026, the risk in the studied region is slightly elevated above the target risk.
- The planned resources in utilities' integrated resource plans shown on slide 21 are enough to meet the shortfalls shown on slide 10 for all years studied.
- Data center flexibility, such as reductions in demand during times of peak demand, can help address the calculated shortfalls.

- Slide 12 indicates that there is essentially no LOLE risk in the year 2025 unless there is a "bad" water year. Will you please clarify whether Slide 12 represents water year 2025 (October 1, 2024 – September 30, 2025)?

CORRECT

- The study finds that the greatest risk to the system is during low hydro years and the evidence, as of December 31, 2025, does not indicate we are in a low hydro year.

- With regard to the presentation's fit to current conditions:
  - The presentation is based on a probabilistic model incorporating 30 years of past weather and hydrological conditions. The model does not reflect actual weather and hydrological conditions presently existing for this winter, such as La Niña. Similarly, the model does not reflect weather and hydrological forecasts for this winter.

THE MODEL CONSIDERS 30 HYDRO YEARS (1989-2018) AND 44 TEMPERATURE YEARS (1979-2022). THE HYDRO YEARS AND LOAD YEARS ARE PAIRED RANDOMLY USING MONTE CARLO DRAWS.

- To gauge the extent to which the model represents current conditions, the key factors are: (1) weather forecasts; (2) hydrological conditions; (3) load conditions; and (4) resource additions and retirements. Thus, for instance, if prevailing and forecasted hydrological conditions are stronger than the average conditions observed in the 30-year dataset used for the model, and holding constant other factors, the "Reliability Position" shown on slide 10 likely underestimates the actual reliability position in the region. The same goes for a winter weather forecast that is milder than the average weather observed over the thirty-year dataset used for the model.

  - Flexibility of data center demand, such as reductions in demand during times of peak load, is one way to help address the shortfalls shown on slide 10.

CORRECT, HOWEVER, DATA CENTER "LOAD FLEXIBILITY" IS OFTEN ACHIEVED WITH ONSITE GENERATION. THIS WOULD MOVE THE PROBLEM FROM ONE SIDE OF THE METER TO THE OTHER, BUT WOULDN'T ELIMINATE THE NEED TO BUILD THE RESOURCES SUBJECT TO THE SUPPLY CHAIN AND OTHER CHALLENGES. TRUE FLEXIBILITY OF COMPUTE LOAD WOULD BE A SIGNIFICANT NEW RESOURCE BUT WE HAVE NOT YET SEEN EVIDENCE OF THIS AT SCALE.

- The Department of Energy's December 16, 2025 Order No. 202-25-11 to Transalta is counterproductive and risks harming reliability in the studied region to the extent the order delays the conversion of Centralia Unit 2 to gas. The order need not be renewed in March 2026 to address the Reliability Positions shown on slide 10 of the presentation.

Please let me know if you have any clarifying questions. Thank you again, and Happy New Year.

Brad Cebulko
m: 317.519.3165

From: Arne Olson <arne@ethree.com>
Sent: Wednesday, December 31, 2025 6:32 PM
To: Brad Cebulko <bcebulko@currentenergy.group>; Fred Heutte <fred@nwenergy.org>
Cc: Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mlenoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>
Subject: RE: E3 NW RA study and Centralia

Hi all, thanks for the good questions this morning. Just following up to let you know that, given the holidays and some upcoming deadlines, we will aim to get you the information you requested by late next week. The information we are digging up is:

- Details on how we are modeling the Canadian Entitlement
- List of the "in-development" resources through 2030
- Achieved LOLE values for each year through 2030

Let me know if there is any additional information you might need, and also if there is any impending deadline that we should be aware of.

Also, here is a link to E3's newest resource adequacy white paper.

https://www.ethree.com/new-framework-resource-adequacy/

As I mentioned during our call, it's intended to be a detailed guidebook for how to evaluate resource adequacy needs across markets and vertically integrated systems. Happy to answer any questions you might have about the white paper, or if any other questions come up about our current NW study.

Happy New Year!

Arne

-----Original Appointment-----
From: Arne Olson
Sent: Monday, December 29, 2025 2:08 PM
To: Arne Olson; Brad Cebulko; Fred Heutte
Cc: Laura Burford; Michael Lenoff; Erik Olson
Subject: E3 NW RA study and Centralia
When: Wednesday, December 31, 2025 8:00 AM-8:25 AM (UTC-08:00) Pacific Time (US & Canada).
Where: Microsoft Teams Meeting

Microsoft Teams Need help?

Join the meeting now

Meeting ID: 256 665 160 678 92
Passcode: Ei7NT9X3

For organizers: Meeting options

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	Order No. 202-26-18

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

Exhibit 2-67a:
E3's Attachment to Email Correspondence with E3

Columbia River Treaty Regime

Sources

https://www.state.gov/bureau-of-western-hemisphere-affairs/details-about-the-key-elements-agreed-between-the-united-states-and-canada-regarding-modernization-of-the-columbia-river-treaty-regime

(Table 1.) https://www.congress.gov/crs-product/R43287

Year	Capacity (MW)1	Generation (MW)2
2024 (Baseline)	1,141	454
2025-2029	660	305
2030	590	278
2031	573	225
2032	565	225
2033	558	225
2034-2044	550	225

How it is modeled

The capacity component of the treaty (1) was interpreted as the capacity BC is able to access and demand at any point in time. After consulting with BPA, we also interpret that BC could demand this amount for a sustained long period of time, such as for two weeks or more, without violating the generation amounts of the treaty (2) which is itself interpreted as the annual average energy for the treaty. This means the treaty's capacity could be requested for longer than the reliability risk periods and present a firm requirement. **Therefore, the capacity component of the treaty was modeled as a firm obligation which increases the region's total reliability need by the same amount in MWs.**

Year	Firm Obligation, MW
2025	660
2026	660
2027	660
2028	660
2029	660
2030	590

In-Development Resources

Sources
https://www.wecc.org/program-areas/reliability-planning-performance-analysis/reliability-modeling/anchor-data-set-ads
https://www.pacificorp.com/energy/integrated-resource-plan.html

Plant-level list in-development resources within the Greater Northwest Study Region with commission dates between 2025-2030. In-development resources are WECC ADS 2034 facilities with confirmed project location, project name, and can be verified online. In-development resources include coal-to-gas plant conversions in Pacificorp's 2025 IRP. Plants with commission dates before January 1 are considered available in the study year. Each resource is assgined to a Transmission Zone based on physical location within the Greater Northwest for zonal modeling.

Annual Capacity Additions (Nameplate MW)							
	2025	2026	2027	2028	2029	2030	Total
Hydro	99	251	78	2	91	-	522
Nuclear	-	-	-	-	-	-	-
Coal	-	-	-	-	-	-	-
Gas	1,339	357	-	-	205	360	2,261
Other	-	-	-	-	-	-	-
Wind	1,026	1,126	460	-	-	-	2,611
Solar	344	1,396	125	-	-	-	1,866
BTM Solar	-	-	-	-	-	-	-
Battery Storage	460	545	-	-	-	-	1,005
Demand Response	-	-	-	-	-	-	-
Total	3,267	3,676	663	2	296	360	8,264

Source	GeneratorKey	Name	State	County	Tranmission Zone	Rated Capacity (Nameplate MW)	Resource Type	Balancing Authority	Commission Date	First Available Year
ADS 2034	2177	Meyers Falls 1 HY	WA	NA	PNW_NE	1	Hydro	AVA	12/31/2024	2025
ADS 2034	2197	Upper Falls Post St 1 HY	WA	NA	PNW_NE	10	Hydro	AVA	1/4/2026	2027
ADS 2034	2393	Cedar Falls 2 HY	WA	NA	PNW_NW	15	Hydro	PSEI	1/1/2026	2027
ADS 2034	2394	Cedar Falls 1 HY	WA	NA	PNW_NW	15	Hydro	PSEI	1/1/2026	2027
ADS 2034	3472	Thompson Falls 2 HY	MT	NA	Inland_NW	5	Hydro	NWMT	6/1/2025	2026
ADS 2034	3479	Thompson Falls 6 HY	MT	NA	Inland_NW	5	Hydro	NWMT	12/1/2024	2025
ADS 2034	3480	Thompson Falls 5 HY	MT	NA	Inland_NW	5	Hydro	NWMT	12/1/2024	2025
ADS 2034	3481	Thompson Falls 4 HY	MT	NA	Inland_NW	5	Hydro	NWMT	3/31/2025	2026
ADS 2034	3486	Holter 4 HY	MT	Lewis&Clark	Inland_NW	10	Hydro	NWMT	6/15/2025	2026
ADS 2034	3487	Holter 3 HY	MT	Lewis&Clark	Inland_NW	10	Hydro	NWMT	7/1/2025	2026
ADS 2034	3488	Holter 2 HY	MT	Lewis&Clark	Inland_NW	10	Hydro	NWMT	8/25/2025	2026
ADS 2034	3489	Ryan 6 HY	MT	NA	Inland_NW	8	Hydro	NWMT	1/1/2025	2026
ADS 2034	3490	Ryan 5 HY	MT	NA	Inland_NW	8	Hydro	NWMT	3/9/2025	2026
ADS 2034	3515	Ryan 3 HY	MT	NA	Inland_NW	8	Hydro	NWMT	12/1/2024	2025
ADS 2034	3517	Ryan 1 HY	MT	NA	Inland_NW	8	Hydro	NWMT	12/1/2024	2025
ADS 2034	3531	Holter 1 HY	MT	Lewis&Clark	Inland_NW	10	Hydro	NWMT	12/1/2025	2026
ADS 2034	3537	Thompson Falls 3 HY	MT	NA	Inland_NW	5	Hydro	NWMT	4/1/2025	2026
ADS 2034	3539	Thompson Falls 1 HY	MT	NA	Inland_NW	5	Hydro	NWMT	6/1/2025	2026
ADS 2034	4925	Boundary 1 HY	WA	NA	PNW_NW	158	Hydro	SCL	8/1/2025	2026
ADS 2034	4966	Long_Lake_1	WA	Lincoln	PNW_NE	9	Hydro	AVA	12/31/2024	2025
ADS 2034	7473	Lagrande 2 HY	WA	NA	PNW_NW	6	Hydro	TPWR	1/1/2024	2025
ADS 2034	7474	Lagrande 3 HY	WA	NA	PNW_NW	6	Hydro	TPWR	1/1/2024	2025
ADS 2034	7475	Lagrande 4 HY	WA	NA	PNW_NW	6	Hydro	TPWR	1/1/2024	2025
ADS 2034	7606	Long_Lake_2	WA	Lincoln	PNW_NE	9	Hydro	AVA	12/31/2024	2025
ADS 2034	7607	Long Lake 3 HY	WA	NA	PNW_NE	18	Hydro	AVA	12/1/2025	2026
ADS 2034	7608	Long Lake 4 HY	WA	NA	PNW_NE	18	Hydro	AVA	1/1/2028	2029
ADS 2034	8613	Ryan 2 HY	MT	Cascade	Inland_NW	9	Hydro	NWMT	12/13/2024	2025
ADS 2034	8614	Ryan 4 HY	MT	Cascade	Inland_NW	9	Hydro	NWMT	12/31/2024	2025
ADS 2034	9698	Gorge 1 HY	WA	NA	PNW_NW	37	Hydro	SCL	1/1/2028	2029
ADS 2034	9699	Gorge 2 HY	WA	NA	PNW_NW	37	Hydro	SCL	1/1/2028	2029
ADS 2034	18045	Boswell Springs Wind WT	WY	Sweetwater	Central_West	320	Wind	PACE	4/1/2024	2025
ADS 2034	18048	Cedar Creek Wind WT	ID	Power	Central_West	152	Wind	PACE	4/1/2024	2025
ADS 2034	18179	Hauser Agg HY	MT	Lewis&Clark	Inland_NW	17	Hydro	NWMT	12/31/2024	2025
ADS 2034	18210	Uinta Agg HY	UT	Uintah	Central_West	1	Hydro	PACE	12/1/2025	2026
ADS 2034	18218	Utility Solar+Storage - PV - S-O	OR	NA	PNW_SW	1	Battery Storage	PACW	1/1/2024	2025
ADS 2034	18224	Big Fork 1 HY	MT	Flathead	PNW_NE	2	Hydro	BPAT	1/1/2027	2028
ADS 2034	18345	Glen Canyon Solar A PV-T	UT	Kane	Central_West	95	Solar	PACE	1/1/2024	2025
ADS 2034	19147	Tower Rd Solar PV-T	OR	Morrow	PNW_NE	120	Solar	BPAT	12/1/2024	2026
ADS 2034	19260	Farmers Irrigation District Coppe	OR	Hood River	PNW_SW	2	Hydro	PACW	1/1/2026	2027
ADS 2034	20916	Oregon Trail Solar PV-T	OR	Gilliam	PNW_NE	41	Solar	BPAT	12/31/2025	2026
ADS 2034	20917	Green River Energy Center PV-	UT	Emery	Central_West	400	Solar	PACE	6/15/2025	2026
ADS 2034	20962	Cedar Springs Wind IV WT	WY	NA	Central_West	350	Wind	PACE	12/31/2024	2025

ADS 2034	20963	Anticline Wind WT	WY	NA	Central_West	101	Wind	PACE	12/31/2024	2025
ADS 2034	20964	Two Rivers Wind LLCWT	WY	Carbon	Central_West	280	Wind	PACE	3/31/2025	2026
ADS 2034	21121	Franklin BESS paired with Solar	ID	Twin Falls	Central_West	60	Battery Storage	IPCO	6/1/2024	2025
ADS 2034	21163	Oregon Trail BESS BA	OR	Gilliam	PNW_NE	41	Battery Storage	BPAT	12/31/2025	2026
ADS 2034	21164	Tower Rd BESS BA	OR	Morrow	PNW_NE	60	Battery Storage	BPAT	12/31/2025	2026
ADS 2034	21215	Jim Bridger 1 ST	WY	Sweetwater	Central_West	578	Gas	PACE	4/1/2024	2025
ADS 2034	21216	Jim Bridger 2 ST	WY	Sweetwater	Central_West	586	Gas	PACE	4/1/2024	2025
ADS 2034	21401	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21402	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21403	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21404	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21405	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21406	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21407	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21408	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21409	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21410	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21411	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21412	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21413	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21414	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21415	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21416	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21417	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21418	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21423	DaveJohnston 1 1 ST	WY	Converse	Central_West	99	Gas	PACE	1/1/2029	2029
ADS 2034	21432	Naughton 1 (natural gas convers	WY	Lincoln	Central_West	156	Gas	PACE	1/1/2026	2026
ADS 2034	21433	Naughton 2 (natural gas convers	WY	Lincoln	Central_West	201	Gas	PACE	1/1/2026	2026
ADS 2034	21678	Additional Hemingway Standalo	ID	Owyhee	Central_West	36	Battery Storage	IPCO	6/1/2024	2025
ADS 2034	21679	Elmore Distributed BESS BA	ID	Elmore	Central_West	3	Battery Storage	IPCO	6/1/2024	2025
ADS 2034	21680	Happy Valley BESS I 1 BA	ID	Canyon	Central_West	39	Battery Storage	IPCO	6/1/2025	2026
ADS 2034	21681	Happy Valley BESS II 1 BA	ID	Canyon	Central_West	39	Battery Storage	IPCO	6/1/2025	2026
ADS 2034	21682	Kuna BESS 1 BA	ID	Ada	Central_West	150	Battery Storage	IPCO	6/1/2025	2026
ADS 2034	21683	Melba Distributed BESS BA	ID	Canyon	Central_West	2	Battery Storage	IPCO	6/1/2024	2025
ADS 2034	21735	Parowan Solar BA	UT	Iron	Central_West	58	Battery Storage	PACE	12/1/2024	2025
ADS 2034	21749	Pump Storage - West 1 PS	OR	Douglas	PNW_SW	35	Hydro	PACW	1/1/2026	2027
ADS 2034	21752	Coffee Creek 1 BA	OR	Washington	PNW_NE	17	Battery Storage	BPAT	6/1/2025	2026
ADS 2034	21753	Constable BESS 1 BA	OR	Washington	PNW_SW	100	Battery Storage	BPAT	12/31/2024	2025
ADS 2034	21754	Seaside BESS 1 BA	OR	Multnomah	PNW_SW	200	Battery Storage	BPAT	6/1/2025	2026
ADS 2034	21755	Troutdale BESS 1 BA	OR	Multnomah	PNW_NE	200	Battery Storage	BPAT	12/31/2024	2025
ADS 2034	22116	Pleasant Valley Solar II 1 PV-T	ID	Ada	Central_West	125	Solar	IPCO	12/1/2026	2027
ADS 2034	22212	Arco Wind WT	ID	Bonneville	Central_West	360	Wind	PACE	12/1/2026	2027
ADS 2034	22215	Faraday Solar B LLC PV-T	UT	Utah	Central_West	525	Solar	PACE	9/30/2025	2026
ADS 2034	22217	Hornshadow Solar II LLC PV-T	UT	Emery	Central_West	200	Solar	PACE	6/30/2025	2026
ADS 2034	22218	Hornshadow Solar LLC PV-T	UT	Emery	Central_West	100	Solar	PACE	6/30/2025	2026
ADS 2034	22220	Parowan Solar PV-T	UT	Iron	Central_West	58	Solar	PACE	12/1/2024	2025
ADS 2034	22231	Rock Creek I Wind 32 WT	WY	Carbon	Central_West	195	Wind	PACE	6/1/2025	2026
ADS 2034	22232	Rock Creek II Wind 66 WT	WY	Albany	Central_West	403	Wind	PACE	9/1/2025	2026
ADS 2034	22256	Buckaroo Solar 1 PV-T	OR	Pendleton	PNW_SW	2	Solar	PACW	9/30/2025	2026
ADS 2034	22257	Buckaroo Solar 2 PV-T	OR	Pendleton	PNW_SW	3	Solar	PACW	9/30/2025	2026
ADS 2034	22262	Antelope Creek Solar LLC PV-T	OR	Jackson	PNW_SW	2	Solar	PACW	4/19/2024	2025
ADS 2034	22264	Black Rock Solar PV-T	WA	Yakima	PNW_NE	100	Solar	BPAT	1/1/2024	2025
ADS 2034	22267	Green Solar LLC PV-T	OR	Culver	PNW_SW	3	Solar	TH_Malin	3/15/2024	2025
ADS 2034	22268	High Top Solar PV-T	WA	Yakima	PNW_NE	80	Solar	BPAT	4/1/2024	2025
ADS 2034	22270	Orchard Knob Solar PV-T	OR	Polk	PNW_NE	2	Solar	BPAT	2/23/2024	2025
ADS 2034	22274	Pilot Rock Solar I PV-T	OR	Umatilla	PNW_SW	2	Solar	PACW	9/30/2025	2026
ADS 2034	22275	Pilot Rock Solar II PV-T	OR	Umatilla	PNW_SW	3	Solar	PACW	9/30/2025	2026
ADS 2034	22276	Pine Grove Solar LLC PV-T	OR	Klamath	PNW_SW	1	Solar	TH_Malin	2/16/2024	2025
ADS 2034	22281	Sunset Ridge Solar LLC PV	OR	Klamath	PNW_SW	2	Solar	TH_Malin	7/25/2024	2025
ADS 2034	22292	Clearwater II 37 WT	MT	Custer	Central_West	103	Wind	PACE	1/2/2024	2025
ADS 2034	22323	BHCE 100 MW Wind WT	CO	TBD	PNW_NE	100	Wind	BPAT	1/1/2026	2027
ADS 2034	22340	Beaver Creek 1 WT	MT	Gallatin	Inland_NW	248	Wind	NWMT	3/1/2025	2026
ADS 2034	22487	Sprague Hydro (North Fork) 1 H	OR	Klamath	PNW_SW	1	Hydro	PACW	1/1/2024	2025
ADS 2034	22546	Wallowa Falls 1 HY	OR	NA	PNW_SW	1	Hydro	PACW	1/1/2026	2027
ADS 2034	22567	DaveJohnston 2 2 ST	WY	Converse	Central_West	106	Gas	PACE	1/1/2029	2029
Pacificorp 2025 IRP	Pacificorp 2025 IRP	E3 Dave Johnston 4 Coal-to-Ga	WY	Converse	Central_West	360	Gas	PACE	12/31/2029	2030

Greater Northwest System Metrics

	Unit	2025	2026	2027	2028	2029	2030
Total Resource Need*	*MW*	49,245	50,737	52,499	54,184	55,879	57,195
Existing Portfolio w/ Retirements**	*MW*	46,716	45,666	45,395	45,388	45,098	44,757
Firm Imports	*MW*	3,750	3,750	3,750	3,750	3,750	3,750
Reliability Position ***before Resource Additions*** Surplus (+) / Shortfall (-)	*MW*	1,221	-1,321	-3,354	-5,046	-7,031	-8,689
"In-Development"*** Firm Resources	*MW*	0	296	407	580	770	1,114
"In-Development" Wind, Solar and Battery projects	*MW*	0	645	1,015	1,316	1,508	1,934

** Total Resource Need includes peak load + planning reserve margin as well as obligation to serve the Columbia River Treaty Regime*

***Does not include new gas capacity from converted coal units, only the coal retirements. New gas capacity from conversion categorized as "In-Development" below. Still includes retirement of Centralia 2, at 687 MW of effective firm capacity.*

*** In-development resources are WECC ADS 2034 facilities with confirmed project location, project name, and can be verified online. Includes new gas capacity from the conversion of coal units. Does not inclue repowering of Centralia 2 as a gas unit.*

System Metrics including "In-Development" Resources	Unit	2025	2026	2027	2028	2029	2030
Reliability Position ***with "In-Development" Resources*** Surplus (+) / Shortfall (-)	*MW*	1,221	-380	-1,932	-3,150	-4,753	-5,641
Loss-of-Load Expectation	*MWh/year*	63	1,212	6,987	20,398	58,132	98,067
	Hours/year	0.14	1.65	5.58	14.70	36.43	56.57
	Days/year	0.01	0.15	0.68	1.77	4.14	6.01
	% chance/year	0.3%	5.2%	21.0%	40.5%	59.4%	67.5%

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-26-18

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

Exhibit 2-67b:
E3's Attachment to Email Correspondence with E3 (as transmitted in Excel form)
[Provided in Native Excel Format]

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-26-18

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

Exhibit 2-68:
Wash. Utils. Comm'n Rejection of Colstrip Investments in Avista Rates

Service Date: December 19, 2025

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. AVISTA CORPORATION, D/B/A AVISTA UTILITIES Respondent.	DOCKET UE-240891 FINAL ORDER 08 REJECTING TARIFF SHEETS; AUTHORIZING AND REQUIRING COMPLIANCE FILING

Synopsis: *The Washington Utilities and Transportation Commission rejects the tariff sheets filed by Avista Corporation d/b/a Avista Utilities (Avista or Company) on October 31, 2024, and revised on December 20, 2024, and allowed its requested rate increase to provisionally go into effect subject to refund. The Commission has considered the full record and requires Avista to file tariff sheets that will result in a decrease in revenue of approximately $5.86 million or 1.0 percent in accordance with the decisions in this Order summarized below. The Commission concludes that Colstrip Units 3 and 4 will be "retired" within the meaning of CETA when Avista transfers its ownership in those units to NorthWestern Energy Corporation (NorthWestern) on January 1, 2026. The Commission further determines that the Abandonment and Acquisition Agreement (A&A Agreement) is not subject to Commission approval because Colstrip is not useful or necessary for Avista's service in Washington at the time of transfer.*

However, the Commission establishes a condition to facilitate review of future property transfers to comply with CETA. Additionally, the Commission finds that Avista acted contrary to its commitment not to support life-extending investments at Colstrip in the 2019 General Rate Case (GRC) Settlement approved in Dockets UE-190334, et al., but declines to impose penalties in this docket for violation of that Settlement. The Commission also finds it appropriate for Avista to include its request to recover 2025 plant additions consistent with Final Order 10/04 and the Settlement Agreement in Avista's 2022 GRC in Dockets UE-220053, et al.

The Commission determines that Avista's Colstrip investments are not used and useful after December 31, 2025, and that such investments should be prorated, except for 13 investments in support of human health and safety. The Commission further requires

Avista to establish the in-service dates of two other investments, the U4 Generator Exciter and the Northern Cheyenne AAQ System, to establish a prorated level of recovery, if any. The Commission determines that Avista has demonstrated the prorated portion of its Colstrip investments are prudent but has not demonstrated prudence of its investment in the two TOFA SmartBurn components and the Baghouse Project, which will not be in service and used and useful to Avista's Washington customers in 2025.

The Commission further requires Avista to refund the return on inventory balances, which were inadvertently included in base rates for 2026, remove these inventory balances from working capital in Avista's next general rate case filing, and to refund any over-collected amounts in the manner described in this Order. The Commission further requires Avista to file an accounting to true-up 2025 Colstrip investments along with the refund, in a compliance filing submitted by March 31, 2026, consistent with the decisions in this Order.

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PROCEDURAL HISTORY

1 On October 31, 2024, Avista Corporation d/b/a Avista Utilities (Avista or Company) filed with the Washington Utilities and Transportation Commission (Commission) proposed revisions to its rates under electric service tariff, Tariff WN U-28, Schedule 99

Colstrip Tracker to recover Avista's portion of investments in the Colstrip Steam Electric Station (Colstrip). Colstrip is a four-unit coal fired electric generation facility operated by Talen MT (Talen),[1] located in Colstrip, Montana.[2] Avista states that it submitted this filing in accordance with Final Order 10/04 in consolidated Dockets UE-220053, UG-220054 and UE-210854, and seeks to recover capital investments incurred from December 31, 2023, through December 31, 2025, in this tariff schedule over the 2025 calendar year.[3] Specifically, Avista's proposed rates reflect an increase of $18.2 million, or 2.7 percent, from $23.9 million in 2024 to $42.6 million, and the Company seeks to recover that balance from customers effective January 1, 2025, over the 2025 calendar year.[4]

2 On December 19, 2024, this matter came before the Commission at the regularly scheduled Open Meeting. Commission staff (Staff) raised concerns about several capital investments reflected in the filing that are potentially unrecoverable by law or imprudent for Washington ratepayers. The Commission voted to suspend the filing for hearing.[5] On December 20, 2024, Avista filed revised tariff sheets, and the Commission issued Corrected Order 01, Complaint and Order Allowing Rates Subject to Later Review and Refund; Setting Matter for Adjudication in this docket (Corrected Order 01), requiring Avista to file revised tariff pages no later than December 23, 2024, and indicating that the increased rates would go into effect on January 1, 2025, subject to refund.[6]

3 On March 6, 2025, the Commission held a prehearing conference before Administrative Law Judge Amy Bonfrisco (ALJ Bonfrisco) and on that same date entered Order 02, granting Avista's request for a Protective Order.

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[1] Kinney, Exh. SJK-1T at 6:11-12.

[2] Kinney, Exh. SJK-1T at 4:16.

[3] *Washington Utilities and Transportation Commission (WUTC) v. Avista Corporation d/b/a Avista Utilities (Avista),* Dockets UE-220053, UG-220054, UE-210854 (*Consolidated*) Tariff Schedule 99 Colstrip 2025 Compliance Filing (October 31, 2024).

[4] Kinney, Exh. SJK-1T at 2:8-16. *See also* Kinney, Exh. SKJ-9C (confidential native workpapers) and SJK-10 (for non-confidential workpapers). The difference between the 2024 Tariff 99 balance for revenue requirement (AMA basis) versus the 2025 Tariff 99 balance (AMA basis) is an increase of $18.7 million. However, when the total revenue requirement runs through the rate design workpapers based on load and allocation factors, the required change in revenue is $18.2 million as provided in witness Kinney's testimony referenced above.

[5] *WUTC v. Avista*, Docket UE-240891, Order 01, Complaint and Order Suspending Tariff Revisions; Allowing Rates Subject to Later Review and Refund (December 19, 2024).

[6] Docket UE-240891, Corrected Order 1 at 2 ¶ 5 and 4 ¶ 20 (December 20, 2024) (hereafter Corrected Order 01).

4 On March 21, 2025, the Commission entered Order 03 Prehearing Conference Order and Notice of Hybrid Evidentiary Hearing adopting the parties' agreed procedural schedule, setting the evidentiary hearing for October 3, 2025,[7] and granting the unopposed petitions for intervention submitted by NW Energy Coalition (NWEC) and Alliance of Western Energy Consumers (AWEC). Order 03 also granted NWEC's and AWEC's requests for case certification, directed each to file their proposed budgets for participatory funding within thirty days,[8] and addressed the filing of testimony and exhibits to be considered in the adjudication of issues raised in this docket for all parties.[9]

5 On March 24, 2025, an Errata Correcting paragraph 18 of the Prehearing Conference Order 03 was issued to include the requirement for the parties to submit five paper copies to the Commission within three business days of electronically filing testimony, exhibits and post-hearing briefs."[10]

6 By April 07, 2025, NWEC and AWEC both timely filed their proposed budgets and requests for fund grants, and on May 12, 2025, NWEC filed a Motion to Revise its Proposed Budget pursuant to Washington Administrative Code (WAC) 480-07-375.

7 On May 27, 2025, the Commission entered Order 04 approving NWEC's revised proposed budget together with the initial proposed budget AWEC submitted.[11]

8 On June 9, 2025, pursuant to the procedural schedule, Avista filed its direct testimony, and exhibits in support of its Tariff WN U-28, Schedule 99 Colstrip Tracker filing in this docket.

9 On June 30, 2025, the Public Counsel Unit of the Attorney General's Office (Public Counsel) filed a motion for relief from Order 03 (Motion) requesting suspension of the

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[7] Docket UE-240891, Prehearing Conference Order; Notice of Hybrid Evidentiary Hearing at 2 ¶ 7, 3 ¶¶ 14-16, and 5 ¶ 20; *See also* Appendix A (March 21, 2025).

[8] Pursuant to RCW 80.28.430, utilities must enter into funding agreements with organizations that represent broad customer interests. The Commission is directed to determine the amount of financial assistance, if any, that may be provided to any organization; the way the financial assistance is distributed; the way the financial assistance is recovered in a utility's rates; and other matters necessary to administer the agreement. See *In re Examination of Participatory Funding Provisions for Regulatory Proceedings,* Docket U-210595, Policy Statement on Participatory Funding for Regulatory Proceedings (November 19, 2021).

[9] *Id*.

[10] Docket UE-240891, Notice of Errata to Order 03 (March 24, 2025).

[11] Docket UE-240891, Order 04, Granting NWEC's Motion to Revised Proposed Budget and Order Approving Proposed Budgets and Fund Grants at 10 ¶¶ 34-35 (May 27, 2025).

Commission's requirement for parties to submit five paper copies of testimony, exhibits, post-hearing briefs, and on July 15, 2024, the Commission entered Order 05, denying the Motion.[12]

10 On July 24, 2025, Staff, Public Counsel, AWEC, and NWEC filed response testimony.

11 On August 15, 2025, the Commission entered a Notice assigning Administrative Law Judge Ann Paisner (ALJ Paisner) to serve as a co-presiding officer with ALJ Bonfrisco and the Commissioners in this matter.

12 On September 12, 2025, NWEC filed a Motion to Strike a Portion of the Rebuttal Testimony of Avista witness Scott J. Kinney (Kinney) in which Kinney incorporated by reference extra-record testimony submitted by Puget Sound Energy witness Ronald J. Roberts (Roberts) in Docket UE-240729 by fully concurring with that testimony and attempting to incorporate those arguments in this docket.[13]

13 On September 16, 2025, Avista filed a response stating that it did not object to NWEC's motion, and did not intend to introduce Roberts' testimony,[14] and after no parties filed any further responses, the Commission entered Order 06, granting NWEC's motion to strike.[15]

14 On September 22, 2025, Avista filed a Motion for Leave to File Revised Exhibit SKJ-13Cr, to substitute the final executed version of the Letter Agreement Re: Enhancement Work Under the Abandonment and Acquisition Agreement Between Avista and NorthWestern Energy (NWE) Regarding Cost Allocation (A&A Agreement), for the previously filed unsigned draft version.[16]

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[12] Docket UE-240891, Order 05, Dening Public Counsel's Motion for Relief From Order 03 Prehearing Conference Order at 3-4 ¶¶ 12-14 (July 15, 2025).

[13] Docket UE-240891, NW Energy Coalition's Motion to Strike a Portion of the Rebuttal Testimony of Avista Corporation Witness Scott J. Kinney at 2-3 ¶ 3 citing Kinney, Ex. SJK-11CT at 3:7-10 (September 12, 2025).

[14] Docket UE-240891, Answer of Avista Corporation to NWEC's Motion to Strike a Portion of the Rebuttal Testimony of Avista Corporation Witness Scott J. Kinney at 2-3 ¶¶ 2- 3 (September 16, 2025).

[15] Docket UE-240891, Order 06, Granting NWEC's Motion to Strike a Portion of the Rebuttal Testimony of Avista Corporation Witness Scott J. Kinney at 3 ¶¶ (September 30, 2025).

[16] Docket UE-240891, Letter Agreement Between Avista and NWE Regarding Cost Allocation, Kinney, Exh. 13Cr (October 1, 2025).

15 On September 24, 2025, the Commission convened a Public Comment Hearing, and over the course of the proceeding received a total of 60 comments from Washington customers opposing Avista's filing. Of the 60 comments received, none support the filing, 59 were opposed, 1 was undecided, and 2 of the 59 were duplicates.[17] Most of the customers opposing the filing raised concerns about the ability to continue paying for rate increases in utility bills, particularly when it would run contrary to the purpose of CETA, lead to subsidizing coal electricity for use by other states, and avert investments from being made in cleaner, less expensive energy sources.[18]

16 On September 26, 2025, the Commission issued Notice of Bench Request No. 01,[19] and Staff timely responded.[20] On this same date, Avista filed proposed time estimates and a consolidated exhibit list on behalf of all parties, and Public Counsel and NWEC filed proposed cross exhibits for the evidentiary hearing.

17 On October 1, 2025, the Commission issued Order 07, granting Avista's Motion for Leave to file revised Exh. SKJ-13Cr, and Avista filed a revised copy of page 3 to Exhibit SJK-11CTr in accordance with Order 06. Avista also filed a Motion to Submit Late-Filed Exhibit SJK-30C,[21] which consisted of the letter agreement between Avista and NWE relating to the precise time of closing under the A&A Agreement.

18 On October 3, 2025, the Commission held an evidentiary hearing in this matter before the Commissioners, with ALJs Bonfrisco and Paisner presiding.

19 On October 7, 2025, the Commission issued Notice of Bench Requests No. 2 and 3 to Avista and NWEC, and on October 10, 2025, requested supplemental briefing from all the parties relating to whether Revised Code of Washington (RCW) 19.405.030(3)

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[17] Docket UE-240891, Offer of Public Comment, Exh. BR-4 at 2-3 ¶¶ 6-7, and UTC Matrix Attachment A (October 10, 2025).

[18] Offer of Public Comment, Exh. BR-4, and UTC Matrix Attachment A at 4-7.

[19] Bench Request No. 1 requested that Staff file as exhibits in this docket, UE-240891, Supplemental Joint Testimony of Exh. JT-3T and JT-4, originally filed in Avista's 2022 general rate case in Dockets UE-220053, UG-220054, and UE-210854. The Commission also requested that Staff provide the specific citation to Final Order 10/04 and Appendix A, which it recommended be the subject of amendment as described in Staff Witness McGuire's Testimony, Exh. CRM -1CT at 31:5 and 37:3.

[20] Docket UE-240891, Staff Response to Bench Request No. 1 and Attachments A and B (September 29, 2025).

[21] Docket UE-240891, Letter Agreement Between Avista and NWE Regarding Closing Timing Under the Abandonment and Acquisition Agreement, Kinney, Exh. SJK-30C (October 1, 2025).

pertains to an "undepreciated investment in fossil fuel resource," to which all parties timely responded.

20 On October 24, 2025, all the parties responded timely and submitted their post-hearing and supplemental briefing.

21 On November 24, 2025, the Commission issued Notice of Bench Request No. 4 requesting that Avista provide the revenue model and supporting workpapers in their native format along with detailed information relating to gross plant, accrued depreciation, and ADFIT and on December 2, 2025, Avista timely responded.

22 **PARTY REPRESENTATIVES.** David Meyer, Chief Counsel, represents Avista. Jeff Roberson, Nash Callaghan and Josephine Strauss, Assistant Attorneys General, represent Staff.[22] Alexandra Kory, Tad Robinson O'Neill, and Robert Sykes, Assistant Attorneys General, represent Public Counsel. Sommer Moser, Michelle Madsen and Tyler Pepple of Pepple Moser, P.C., represent AWEC. Yochanan Zakai and Orran Balagopalan of Shute, Mihaly & Weinberger LLP., represent NWEC.

BACKGROUND

23 **Clean Energy Transformation Act (CETA).** In 2019, the Washington State Legislature passed the Clean Energy Transformation Act (CETA),[23] codified in RCW Chapter 19.405. In the face of immediate and significant threats posed by climate change, CETA requires that each Washington electric utility "eliminate coal-fired resources from its allocation of electricity" no later than December 31, 2025,[24] that all retail sales of electricity are "one hundred percent carbon-neutral by January 1, 2030,"[25] and that by January 1, 2045 "one hundred percent of all sales of electricity to Washington retail customers" are supplied by either non-emitting or renewable electricity generation

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[22] In formal proceedings such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See* RCW 34.05.455.

[23] Laws of 2019, Ch. 288, §§ 1–13 and 26. Codified at RCW 19.405.

[24] RCW 19.405.030(1). *See also* RCW 19.405.020(1) which defines "*Allocation of electricity*" for the purposes of setting electricity rates as "the costs and benefits associated with the resources used to provide electricity to an electric utility's retail electricity consumers that are located in this state."

[25] RCW 19.405.010 (2) and RCW 19.405.040(1).

resources.[26] CETA promotes a transition to a clean energy economy,[27] provides incentives for clean alternative energy sources,[28] and expands the meaning of "public interest" under Title 80 RCW.[29]

24 **Settlement Agreement in Avista's 2022 General Rate Case (GRC).** On December 12, 2022, the Commission approved the Colstrip Tracker and Tariff Schedule 99 in its resolution of Avista's 2022 GRC in Final Order 10/04, approving with conditions a Full Multiparty Settlement (Settlement or 2022 GRC Settlement) with an annual true-up mechanism.[30] Among other terms, the Tariff Schedule 99 Colstrip Tracker had a rate effective date of December 21, 2022, that would be reset each January 1st via a filing made each October 31st until all prudently incurred costs were recovered,[31] including "operating and maintenance ("O&M") and other expenses, depreciation expense, decommissioning and remediation ("D&R") costs, and return on rate base."[32] However, "non-O&M items" would be recovered "on a one-year lag, using actuals through August 31st and estimates through December 31st of the filing year,[33] but transmission investments and costs included in Avista's Energy Recovery Mechanism (ERM) were excluded.[34]

25 **Settlement Agreement in Avista's 2019 GRC.** On March 25, 2020, the Commission entered Final Order 09 in Avista's 2019 GRC, approving without condition, a Partial

[26] RCW 19.405.010(2) and RCW 19.405.050(1).

[27] RCW 19.405.010(1).

[28] RCW 19.405.010(4).

[29] RCW 19.405.010(6). In enacting CETA, the Legislature found that the public interest includes: (a) the "equitable distribution of energy benefits and reduction of burdens to vulnerable populations and highly impacts communities;" (b) "long-term and short-term public health, economic, and environmental benefits;" and (c) "the reduction of costs and risks and energy security and resiliency."

[30] *WUTC v. Avista*, Dockets UE-220053, UG-220054, & UE-210854 (*Consolidated*), Final Order 10/04, Rejecting Tariff Sheets; Granting Petition; Approving and Adopting Full Multiparty Settlement Stipulations Subject to Conditions; Authorizing and Requiring Compliance Filing at 21-22 ¶¶ 63-64 (December 12, 2022). Hereinafter referred to as "Avista 2022 GRC."

[31] Dockets UE-220053 et. al., Avista 2022 GRC, Final Order 10/04 at 23 ¶ 65 and Supplemental Joint Testimony, Exh. JT-3T at 6:12-14 and 10:20-21.

[32] Dockets UE-220053 et. al., Supplemental Joint Testimony, Exh. JT-3T at 3:1-5 and Avista, Tariff WN U-28, Schedule 99, Second Substitute Revision Sheet 99 (filed December 20, 2024).

[33] Dockets UE-220053 et. al., Supplemental Joint Testimony, Exh. JT-3T at 6:12-14 and 10:20-21.

[34] Dockets UE-220053 et. al., Supplemental Joint Testimony, Exh. JT-3T at 3:1-5 and Avista, Tariff WN U-28, Schedule 99, Second Substitute Revision Sheet 99 (filed December 20, 2024).

Multiparty Settlement, in which Avista agreed "that it will not support capital expenditures at Colstrip that go beyond routine capital maintenance costs that extend the plant's operational life beyond December 31, 2025."[35] However, since Avista now seeks to recover certain long-lived investments, NWEC, Staff, and Public Counsel raise several concerns about the requested recovery being prohibited under the parties' 2019 Partial Multiparty Settlement, which is addressed in detail in detail in Section IV below.

26 **Colstrip Ownership and Operations Agreement (O&O Agreement), and Development of the Abandonment and Acquisition Agreement (A&A Agreement).** Avista seeks recovery of its portion of investments in Colstrip Units 3 and 4.[36] Colstrip Units 1 and 2 were closed in January 2020, and Colstrip Units 3 and 4 remain in operation.[37] At present, Avista owns 15 percent of Colstrip Units 3 and 4, with the other 85 percent divided among other entities as follows:[38]

	Colstrip Unit 3	**Colstrip Unit 4**
Avista Corporation	15%	15%
NorthWestern Energy	--	30%
PacifiCorp	10%	10%
Puget Sound Energy	25%	25%
Portland General Electric Company	20%	20%
Talen MT	30%	--

27 "Avista's obligations regarding its ownership in Colstrip are governed by the Ownership and Operations Agreement dated May 6, 1981" (O&O Agreement).[39] Under the O&O Agreement, Avista must "fund costs to operate and maintain Colstrip Units 3 and 4 so long as Avista has an ownership interest in the plant."[40] This includes requiring each owner to provide the plant with the amount of coal needed to generate each owner's share of the plant's minimum operating capacity.[41] Each year, the owners of the Colstrip units

[35] *WUTC v. Avista Corp.*, Dockets UE-190334, UG-190335 and UE-190222 (*Consolidated*) Final Order 09, Approving and Adopting Partial Multiparty Settlement Stipulation Appendix A at 12-13 ⁋ 14(j) (March 25, 2020).

[36] Kinney, SJK-1T at 4:16.

[37] Kinney, Exh. SJK-1T at 4:15-17.

[38] Kinney, Exh. SJK-1T at 4:20-21 and 5:1-2.

[39] Kinney, Exh. SJK-1T at 5:4-5 citing to Kinney, Exh. SJK-2C.

[40] Kinney, Exh. SJK-1T at 5:7-9.

[41] Kinney, Exh. SJK-1T at 5:9-10.

must approve a budget, but because Avista holds a 15 percent ownership, it is "a minority owner and cannot unilaterally" approve or deny the budget with its vote.[42]

28 To comply with CETA's mandate to have coal-fired generation removed from its allocation of electricity by December 31, 2025, Avista made several attempts to sell or dispose of its share of Colstrip Units 3 and 4, but maintains there were limited parties interested in acquiring its ownership interest.[43] Specifically, Avista contends that "[b]y the time NWE and Talon [sic] emerged," they were "the only entities both interested and operationally capable of succeeding to Avista's interest," but that "the window for parallel negotiations with alternative buyers had effectively closed."[44] Additionally, because "extracting even a nominal payment would have jeopardized the timetable and invited further transactional failure," and Avista needed to continue "to preserve its contractual and physical rights on the Colstrip Transmission System," it maintains that any "transaction that unduly encumbered, subordinated, or alienated those rights would have effectively impaired Avista's ability to comply with both its resource and adequacy obligations and clean-energy targets."[45] Thus, "only NWE and Talon [sic] remained as viable counterparties…[and] [s]ince Talen was in negotiations with PSE to acquire their ownership interests in Colstrip, Avista began negotiations with NWE."[46] Then on January 16, 2023, Avista entered into the A&A Agreement with NWE, in which Avista transferred its 15 percent ownership interest in Colstrip Units 3 and 4.[47] Avista entered into the A&A agreement with NWE without seeking Commission approval**,**[48] and "the closing of the transactions under the A&A Agreement shall occur precisely at 12:00:00 a.m. Pacific time on January 1, 2026.[49]

DISCUSSION AND DECISION

I. Applicable Law

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[42] Kinney, Exh. SJK-1T at 7:3-5 citing to Kinney, SJK-2C, Section 17(f)(ii) of O&O Agreement.

[43] Kinney, Exh. SJK-11CT at 6:3-4.

[44] Kinney, Exh. SJK-11CT at 6:8-10.

[45]Kinney, Exh. SJK-11CT at 6:11-12, 6:15-16 and 6:18-20.

[46] Kinney, Exh. SJK-11CT at 6:22-23 and 7:1.

[47] Kinney, Exh. SJK-3C, Colstrip Units 3& 4 Interests Abandonment and Acquisition Agreement by and between Avista Corporation and NorthWestern Corporation ("A&A Agreement) (January 16, 2023). *See also* Kinney, Exh. SJK-13cr, Revised A&A Agreement (August 25, 2025).

[48] Mullins, Exh. BGM-1CT at 2:9-11 and 5:3-12.

[49] Kinney, Exh. SJK-30C.

29 The Legislature has entrusted the Commission with broad discretion to regulate and set rates in the public interest[50] that are just, fair, reasonable and sufficient,[51] and to balance the needs of the public to have safe, reliable, and appropriately priced services, while also assuring that the utilities earn enough to remain in business.[52] The Commission has previously interpreted the fair, just, reasonable, and sufficient standard to mean that "rates that are *fair* to customers and to the Company's owners; *just* in the sense of being based solely on the record developed in a rate proceeding; *reasonable* in light of the range of possible outcomes supported by the evidence; and *sufficient* to meet the needs of the Company to cover its expenses and attract necessary capital on reasonable terms."[53]

30 If, after hearing, the Commission finds that the rates charged by the utility are:

> . . . unjust, unreasonable, unjustly discriminatory or unduly preferential, or in any wise in violation of the provisions of the law, or that such rates or charges are insufficient to yield a reasonable compensation for the service rendered, the commission shall determine the just, reasonable, or sufficient rates, charges, regulations, practices or contracts to be thereafter observed and in force, and shall fix the same by order.[54]

31 For proposed rates, as in this case, the Commission may enter an order under this same standard as if the proposed rates were already effective.[55]

32 As a general matter, the burden of proving that a proposed increase is just and reasonable is upon the public service company,[56] and the burden of proving that the presently effective rates are unreasonable rests upon any party challenging those rates.[57]

33 As discussed above, in 2019 the Legislature expanded the meaning of public interest under Title 80 RCW in passing CETA. As Washington state transitions to a clean energy

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[50] RCW 80.01.040(3)

[51] *PacifiCorp v. WUTC*, 194 Wn. App 571 at 587 quoting RCW 80.28.010 (2016).

[52] *People's Org. for Wash, Energy Res. (POWER) v. WUTC*, 104 Wn.2d 798 at 808 (1985).

[53] *WUTC v. Avista Corp.*, Dockets UE-160228 & UG-160229, Order 06 at 47 ¶ 79 (Dec. 15, 2016) (emphasis in original).

[54] RCW 80.28.020.

[55] RCW 80.04.130(1).

[56] *Id*.

[57] *WUTC v. Pacific Power and Light Company*, Cause No. U-76-18 (Dec. 29, 1976) (internal citations omitted).

economy, the Legislature provided that the public interest includes: "The equitable distribution of energy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health, economic, and environmental benefits and the reduction of costs and risks; and energy security and resiliency."[58] In achieving these policies the Legislature directed that, "there should not be an increase in environmental health impacts to highly impacted communities."[59]

34 Further, in enacting of RCW 80.28.425, which requires utilities to propose multi-year rate plans (MYRP) when filing a general rate case (GRC), the Legislature permitted the Commission to consider equity as part of its public interest evaluation.[60] Following the enactment of the MYRP statute, the Commission indicated its commitment to considering equity while regulating in the public interest: "So that the Commission's decisions do not continue to contribute to ongoing systemic harms, we must apply an equity lens in all public interest considerations going forward."[61] The Commission also explained that regulated companies should be prepared to address equity considerations in future cases: "Recognizing that no action is equity-neutral, regulated companies should inquire whether each proposed modification to their rates, practices, or operations corrects or perpetuates inequities."[62]

II. Application of RCW 19.405.030 - Interpretation of "*Retirement*"

35 CETA requires the following:

> The commission must allow in rates, directly or indirectly, amounts on an investor-owned utility's books of account that the commission finds represent prudently incurred undepreciated investment in a fossil fuel generating resource that has been retired from service when:
>
> (a) The retirement is due to ordinary wear and tear, casualties, acts of God, acts of governmental authority, inability to procure or use fuel, termination or expiration of any ownership, or a operation agreement affecting such a fossil fuel generating resource; or

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[58] RCW 19.405.010(6).

[59] *Id*.

[60] RCW 80.28.425(1)

[61] *WUTC v. Cascade Natural Gas Corp.*, Docket UG-210755 Order 10 ¶ 58 (Aug. 23, 2022).

[62] *Id*.

(b) The commission finds that the retirement is in the public interest.[63]

36 Avista argues as follows: (1) that RCW 19.405.030(3) provides for recovery of prudently incurred, "undepreciated investment of fossil fuel generation resources;"[64] (2) that the statute "expressly allows for direct or indirect recovery" or the "full value of investments placed in service in 2024 and 2025;"[65] (3) that the A&A Agreement constitutes a "termination of ownership" under the statute and provides the "reason for the Commission to allow recovery"[66] of its undepreciated investments in fossil fuel generating resources;[67] and that (4) Avista's "retirement of the facility is in the public interest."[68] Additionally, Avista argues that "it is well within the Commission's authority to approve recovery of the full value of the Colstrip investments that are or will be placed in service in 2024 and 2025, regardless of their depreciable lives."[69] To support its argument, Avista cites the definitions of '*retire*' and '*retirement'* provided by the Financial Accounting Standards (FASB), which codifies the Generally Accepted Accounting Principles (GAAP) as instructive. FASB defines '*retirement*' as:

> The other-than-temporary removal of a long-lived asset from service [that]…encompasses, sale, abandonment, recycling, or disposal in some other manner…[and] [a]fter an entity retires an asset, [treats] that asset [as] no longer under the control of that entity, no longer in existence, or no longer capable of being used in the manner for which the asset was originally acquired, constructed, or developed."[70]

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[63] RCW 19.405.030(3).

[64] Kinney, Exh. SJK-1T at 10:24-27 and SJK-11CT at 11:5-9.

[65] Kinney, Exh. SJK-1T at 11:1-3.

[66] Kinney, Exh. SJK-1T at 11:4-5, and SJK-11CT at 11:10-11.

[67] Avista explains that the plain language of RCW 19.405.030(3) "clearly embrace more than just a coal-fired resource" to employ a more expansive use of this term "to allow recovery of undepreciated investment in a gas plant, given the intent and requirements of the Chapter…to eliminate use of fossil fuel generation by 2045. *WUTC v. Avista*, Docket UE-240891, Post-Hearing Brief of Avista (Avista's Post Hearing Brief) at 27- 28 ¶¶ 84-87 (October 24, 2025).

[68] Kinney, Exh. SJK-1T at 11:9-11.

[69] Docket UE-240891, Rebuttal Testimony of Elizabeth M. Andrews, Exh. EMA-1CT at 1:19-20 (August 25, 2025).

[70] Andrews, Exh. EMA-1CT at 20:3-11 citing Financial Accounting Standards Board (FASB) and Accounting Standards Codification (ASC), which codifies GAP definition for retirement 410-20-20 at: https://asc.fasb.org/MasterGlossary.

37 Avista further maintains that the accounting definition is consistent with that of the Office of Washington State Auditor, which considers the retirement of a tangible asset to include abandonment.[71] Andrews reasons that "when using these appropriate definitions of retirement…the [A&A] Agreement between Avista and NWE ("divestiture") clearly meets the definition…contemplated by the legislation,"[72] which includes "termination or expiration of any ownership."[73]

38 Respectively, based on varying interpretations of the term "retirement" under CETA and the different application of prudency and used and useful standards, Staff, Public Counsel, NWEC and AWEC disagree with Avista's contention that CETA does not restrict allowance of non-life extending assets in rates.

39 Specifically, Staff argues that Avista failed to meet its burden to recover capital investments under RCW 19.405.030(3)(a) or (b) because the Company did not demonstrate it made prudent investments in undepreciated property before retirement of that property from service.[74] Staff explains that by using the phrase '*has been retired*,' "the Legislature phrased the retirement requirement in present perfect tense…to express a past event that has present consequences," thus reasoning that Avista "cannot recover costs under RCW 19.405.030(3) unless it has already retired Colstrip."

40 Similarly, Public Counsel argues that "[b]y the plain language of the statute, the provision only applies to a resource that has been retired from service." [75] Given that "Avista may no longer receive power from Colstrip after December 31, 2025, but…will continue operations beyond that date," [76] Public Counsel maintains under RCW 19.405.030(3), the plant will not be effectively "retired from service" after December 31, 2025.[77]

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[71] Andrews, Exh. EMA-1CT at 20:8-11.

[72] Andrews, Exh. EMA-1CT at 20:12-15.

[73] Docket UE-240891, Rebuttal Testimony of Scott J. Kinney, SJK-11CT at 10:24-26.

[74] Docket UE-240891, Post-Hearing and Supplemental Brief of Commission Staff (Staff's Post Hearing Brief) at 13 ¶ 31 (October 24, 2025).

[75] Docket UE-240891, Response Testimony of Jean Marie Dreyer on Behalf of the Washington State Office of the Attorney General Public Counsel Unit (Public Counsel Response Testimony), Dreyer, Exh., JMD-1CT at 4:15-19 (July 24, 2025).

[76] *Id*.

[77] Docket UE-240891, Response Testimony of Jean Marie Dreyer on Behalf of the Washington State Office of the Attorney General Public Counsel Unit (Public Counsel Response Testimony), Dreyer, Exh., JMD-1CT at 4:15-19 (July 24, 2025).

41 NWEC argues that "CETA requires the Commission to allow utilities to recover undepreciated investment in a fossil fuel asset only if '*it has been retired from service,*'" to mean actually physically retired.[78] To support this contention, NWEC applies a used and useful analysis and argues that because CETA mandates electric utilities to eliminate coal-fired resources from their allocation of electricity by December 31, 2025, RCW 19.405.030(3) cannot authorize the recovery of undepreciated investment in fossil fuels remaining in service beyond December 31, 2025.[79] NWEC further argues that Avista rate payers will not benefit from Colstrip's operation beyond December 31, 2025, and therefore cannot be required to pay for Colstrip's long term operation.[80] Additionally, NWEC contends that FASB's "highly specialized accounting" definition of "retirement" should not be used to determine whether Avista qualifies to recover undepreciated investment pursuant to RCW 19.405.030(3).[81] Instead, NWEC proposes the Commission apply a dictionary definition, and interpret *'retirement'* to mean that fossil fuel plants must actually cease operations to be retired from service.[82] Using this standard, NWEC argues, the Commission must treat Colstrip Units 3 and 4 as not having been retired, since these fossil fuel resources will remain in-service and continue operating beyond 2025.[83]

42 Finally, AWEC highlights that although the legislative intent of CETA was to eliminate coal-fired resources from each electric utility's allocation of electricity, RCW 19.3405.030 "did not necessarily mandate retirement, sale, or any other property transactions with respect to coal plants."[84] Rather, AWEC maintains that "the statute only stated that the cost and benefits were to be removed from utility rates," and reasons that "[i]n the absence of a sale or retirement by the deadline, it must therefore be assumed that Colstrip 3& 4 would presumably become a merchant power plant owned and operated by Avista but not recoverable through utility rates."[85]

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[78] Docket UE-240891, Testimony of Bradley T. Cebulko on Behalf of NW Energy Coalition, Cebulko, Exh. BTC-1CT at 11:13-15 (July 24, 2025).

[79] Cebulko, Exh. BTC-1CT at 12:1-3 and 37:12.

[80] Cebulko, Exh. TC at 21:2-22:6.

[81] McCloy, Exh. BTC-1CT at 5:6-12.

[82] McCloy, Exh. BTC-1CT at 5:9-11.

[83] McCloy, Exh. BTC-1CT at 4:14-15 and 5:22-26. *See also* McCloy, Exh. LCM 1T at 8:10-12 and 13:10-16.

[84] Docket UE-240891, Response Testimony of Bradley G. Mullins on Behalf of Alliance Western Energy Consumers, Mullins, BGM-1CT at 6:15-16 (July 24, 2025).

[85] Mullins, BGM-1CT at 6:18-21.

Commission Determination:

43 RCW 19.405.030(3), provides as follows:

> (3) The commission must allow in rates, directly or indirectly, amounts on an investor-owned utility's books of account that the commission finds represent <u>prudently incurred undepreciated investment in a fossil fuel generating resource that *has been retired from service* when</u>:
>
> (a) The retirement is due to ordinary wear and tear, casualties, acts of God, <u>acts of governmental authority</u>, inability to procure or use fuel, <u>*termination or expiration of any ownership*</u>, or an operation agreement affecting such a fossil fuel generating resource; or
>
> (b) The commission finds that the retirement is in the public interest.[86]

44 To understand what the Legislature meant by the word *'retire*,' the Commission begins its review with the canons of statutory interpretation and looks at the language itself to determine intent. [87] If the meaning is plain on its face, then we give effect to that meaning, as an expression of legislative intent.[88] "A statutory provision's plain meaning is to be discerned from the ordinary meaning of the language at issue, the context of the statute in which that provision is found, related provisions, and the statutory scheme as a whole."[89] If after a plain language analysis the provision remains susceptible to more than one reasonable interpretation, only then will we employ the tools of statutory construction to discern its meaning.[90]

45 Here, there are two competing interpretations of the phrase '*that has been retired from service*,' under RCW 19.405.030. Staff, NWEC, and Public Counsel argue that the Commission should rely on the ordinary meaning, or dictionary definition of "retire," and require that the fossil plant must actually cease operations,[91] or otherwise be inoperable

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[86] RCW 19.405.030(3) (emphasis added).

[87] *Tingey v. Haisch,* 159 WN.2d 652, 657, 152.P3d 1020 (2007).

[88] *Id.*

[89] *Tingey v. Haisch,* 159 WN.2d 652, 657, 152.P3d 1020 and *State v. Ervin*, 169 Wn.2d 815, 820, 239 P.3d 354 (2010).

[90] *Id* citing *Dep't of Ecology v. Campbell & Gwinn, LLC*, 146 Wn2d 9, 12 (2002).

[91] NWEC's Post Hearing Brief at 6 ¶14.

"to end the working life of coal power."[92] Additionally, Staff argues that the Commission should "find the [L]egislature's use of verb tense holds significance"[93] in construing the statute. Conversely, Avista argues that the Commission should apply the technical accounting definition of retirement, which is well accepted in the industry, codified by the FASB to support GAAP's definition of retirement, and is consistent with the State of Washington's State Auditor's Office definition.[94] Avista further highlights that the technical accounting definition of "retirement" is more appropriate given that: (1) under both the GAAP and Washington State Auditor's definitions, the asset will be retired as of January 1, 2026; (2) RCW 19.405.030's title itself refers to "Coal-fired resources – Depreciation schedule – Penalties;" (3) standard accounting terms and concepts are referenced throughout RCW 19.405.030 (i.e., "investor-owned utility's books of accounts," "undepreciated investments," "depreciation schedules"); and (4) the consistent requirement in RCW 19.405.030(2) directing the Commission "to accelerate depreciation schedules for any coal-fired resources to a date no later than December 31, 2025."[95]

46 We acknowledge that courts have frequently held that "when a word has a well-accepted, ordinary meaning, a regular dictionary may be consulted to ascertain the term's definition."[96] "However, where any otherwise common word is given a distinct meaning in a technical dictionary or other technical reference and has a well-accepted meaning within the industry, and when the word is used in a rule promulgated by an expert agency familiar with the technical meaning, courts should turn to a technical rather than a general purpose dictionary to resolve ambiguities in its definition."[97]

47 Here, we agree with Avista that it is not a coincidence that the Legislature: (1) included a description in the title for RCW 19.405.030 of "Coal-fired resources – Depreciation schedule – Penalties;" nor (2) referenced standard accounting terms (i.e., "investor-owned utility's books of accounts," "undepreciated investments," and "depreciation schedules") throughout RCW 19.405.030.

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[92] Public Counsel's Post Hearing Brief, at 16 ¶ 49.

[93] Staff's Post Hearing Brief at 13 citing *Crown W. Realty, LLC v. Pollution Control Hearings Board*, 7 Wn.App. 29, 710, 738, 435 P.3d 288 (2019).

[94] Docket UE-240891, Post-Hearing Brief of Avista (Avista's Post Hearing Brief) at 9 ¶ 28-29 (October 24, 2025).

[95] Avista's Post Hearing Brief at 8-9 ¶¶ 25-27.

[96] *City of Spokane ex. rel. Wastewater Mgmt. Dep't v. Dep't of Revenue,* 145 Wn.2d 445, 454, 38 P.3 1010 (2002).

[97] *Id.*

48 In further examining the statutory context, we also give weight to the mandate in RCW 19.405.030(1)(a) that each electric utility "eliminate coal-fired resources from its allocation of electricity" on or before December 31, 2025. Under RCW 19.405.020(1), "'[a]llocation of electricity' means, for the purposes of setting electricity rates, the costs and benefits associated with the resources used to provide electricity to an electric utility's retail electricity consumers that are located in this state."[98] In other words, because CETA regulates electricity as a commodity, it does not "not necessarily mandate retirement, sale, or any other property transactions," [99] or require that the plant actually cease operations or otherwise be inoperable to end the working life of coal power. Rather, it only states that the cost and benefits are to be removed from utility rates.

49 Next, regarding Staff's argument that a Legislature's use of verb tense holds significance, we acknowledge that a statute framed in the "present-perfect tense can refer to either (1) an act, state, or condition that is not completed or (2) a past action that comes up to and touches the present…[where] one might employ the present-perfect tense to describe situations involving a specific change of state that produces a continuing result."[100] However, we are not persuaded that the semantics of the single phrase, "has not been retired", is controlling here because such framing of the issue is overly narrow and fails to account for the fact that by the time the rates go into effect on January 1, 2026, the plant will effectively be retired in Washington state.

50 While we acknowledge that RCW 19.405.030(3)(b) does not explicitly define each of the triggering events for retirement, we find that at least two of those triggering events exist here. These include: (1) acts of governmental authority (i.e., CETA's December 31, 2025, deadline mandating that coal be out of rates for Washington ratepayers); and (2) Avista's "termination or expiration of ownership" by entering into the A&A Agreement with NWE to transfer its 15 percent ownership of Colstrip Units 3 and 4 effective January 1, 2026. Simply stated, the purpose of CETA's mandate incorporated in RCW 19.405.030(1)(a) is to remove coal-fired electricity from Washington's electricity supply by the end of December 31, 2025; and such mandate may still be accomplished if Colstrip Units 3 & 4 are transferred and no longer providing electricity in Washington, even if they are not entirely shutdown.

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[98] RCW 19.405.020(1).

[99] Mullins, BGM-1CT at 6:15-16.

[100] *Hewitt v. United States*, 606 U.S. 419, 427-428, 145 S.Ct. 2165, 2172-74, 222 L.ED.2d 613 (2025) citing the Chicago Manual of Style §5.132, p. 268 (17th ed. 2017).

51 Based on the above, we find that Avista will have retired coal-fired electricity from its electrical supply in accordance with the requirements set forth in RCW 19.405.030. Accordingly, to facilitate a fair, equitable and just transition, we hold that Avista shall not be precluded from recovering undepreciated investments in Colstrip Units 3 and 4, and shall be afforded the opportunity to recover any prudently incurred and used and useful capital investments in Colstrip, as discussed in detail below in Section VI, Investments in Colstrip.

III. Asset Transfer

52 Avista entered into the A&A Agreement with NWE on January 16, 2023, to comply with the CETA requirement to eliminate coal-fired resources from its allocation of electricity in Washington rates after December 31, 2025. The A&A Agreement transfers the Company's 15 percent ownership interest in Colstrip Units 3 and 4 to NorthWestern Energy (NWE).[101] On October 1, 2025 the parties amended the agreement to reflect a change in the timing of the actual transfer of ownership, which will now occur on January 1, 2026, after the December 31, 2025 deadline in CETA.[102]

53 AWEC argues that the A&A Agreement should have been brought before the Commission for approval under RCW 80.12.020. AWEC states in its brief that the disposal of such property is within the sole jurisdiction of the Commission to authorize "so long as the property or facility is necessary or useful in performance of the utility's duties." [103] AWEC acknowledges that beginning January 1, 2026, Colstrip would not be necessary or useful in the performance of any Avista duties to Washington customers, and that even if the agreement were to close in 2026, the Commission should nevertheless exercise jurisdiction over the A&A Agreement because the agreement transferred Avista's interest in Colstrip Unit 3 and 4 prior to the time when CETA precludes its inclusion in rates."[104] AWEC further argues that the A&A Agreement has significant impacts on Avista's Washington ratepayers.[105] AWEC points out the inconsistency between Avista's position that the Commission does not have jurisdiction

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[101] Kinney, Exh. SJK-1T at 14:15-16; Kinney, Exh. SJK-11CT at 6:19-20.

[102] Kinney, Exh. SJK-30C.

[103] Post Hearing Brief on Behalf of Alliance of Western Energy Consumers (AWEC's Post Hearing Brief) at 3 ¶ 6 (October 24, 2025).

[104] AWEC's Post Hearing Brief at 2 ¶ 6, 11 (citing Docket No. UE-001878, Fourth Supplemental Order at ¶ 15 (Jan. 25, 2002).

[105] AWEC's Post Hearing Brief at 5-6 ¶ 11-12 (citing Response Testimony of Bradley G. Mullins on Behalf of Alliance Western Energy Consumers, Exh. BGM-1CT at 7:8-9:14 (July 24, 2025).

over the agreement under RCW 80.12.020 and its separate argument that it should fully recover its investment in the assets transferred in the A&A Agreement as a "retirement" under RCW 19.405.030(3). AWEC emphasizes that "it is unreasonable for the Company to request cost recovery of life-extending investments in a proceeding where it is also arguing that the A&A Agreement, which obligates Avista to pay for and then transfer the value of those investments to NorthWestern for the benefit of NorthWestern's ratepayers, is outside of the Commission's jurisdiction."[106] AWEC further argues that it would be similarly unreasonable for the Commission to rely on the time of transfer to avoid asserting jurisdiction over the agreement.[107] Finally, AWEC argues that in the absence of a sale, Avista could have retained its ownership share and operated its portion of Colstrip as a merchant plant that is not recoverable through utility rates without impact or consequence to ratepayers.[108]

54 NWEC argues that Avista never obtained Commission approval prior to assigning its Colstrip assets in the A&A Agreement upon the January 2023 execution of the agreement in violation of RCW 80.12.020(1).[109] NWEC further argues that Avista's argument that Colstrip will no longer be used and useful to the public as of December 31, 2025, is circular, because Avista is abandoning Colstrip to NWE as of the date of that agreement and suggests that if Avista's interpretation is correct, then "[s]uch interpretation would effectively render RCW 80.12.020 meaningless."[110] NWEC argues that Avista fundamentally mischaracterizes the A&A Agreement as governing only the time period after which Colstrip Units 3 and 4 will no longer provide electricity to the State's ratepayers, and that Avista effectively "contracted away its right to vote on all non-remediation items between January 16, 2024 and December 31, 2025.[111] While NWEC states that it is not asking the Commission to void the A&A Agreement, it maintains that the Commission should not allow Avista to both avoid review of the A&A Agreement and fully recover costs that allow Colstrip to continue operating beyond December 31, 2025.[112]

[106] AWEC Post Hearing Brief at 6 ¶ 12.

[107] AWEC's Post Hearing Brief at 8-7:2.

[108] BGM-1CT at 6:18-7:2; AWEC Post Hearing Brief at 8 ¶ 16.

[109]Brief of NW Energy Coalition Opposing Avista Corporation's 2024 & 2025 Colstrip Investments (NWEC's Post Hearing Brief) at 8 ¶ 19 (October 24, 2025).

[110] NWEC's Post Hearing Brief at 8-9 ¶ 20.

[111] NWEC's Post Hearing Brief at 9 ¶ 21.

[112] NWEC's Post Hearing Brief at 9 ¶ 23.

55 Staff did not address in its post hearing briefing whether RCW 80.12.020 applies to the A&A Agreement, or if Commission review and approval was required before entering into this agreement. However, Staff witness McGuire does raise concerns that "Avista did not cast its votes on the 2024 and 2025 Colstrip capital budgets in a manner that was consistent with the public interest" and that the A&A Agreement "does not relieve Avista of its obligation to adhere to the terms of the 2019 GRC Settlement."[113]

56 Public Counsel suggests that the Commission consider the transfer agreement in its prudence analysis and "order that the Company prorate the recovery of those investments in rates and disallow the remainder based on a finding that their transfer is imprudent."[114] In briefing, Public Counsel states that "unless and until Avista obtains Commission approval for its agreement with NorthWestern, the transaction may be invalid under the statute" and that it "agrees with AWEC's proposal for Avista to submit a separate filing for the Commission to evaluate the prudence of its agreement with NorthWestern."[115]

57 Avista argues on rebuttal that it was not required under RCW 80.12.020 to obtain Commission approval for the A&A Agreement with NWE, which applies to the sale, lease, assignment or other transfer of facilities that are necessary, or useful in the performance of its duties to the public. Further, Avista acknowledges that as of December 31, 2025, by operation of CETA, Colstrip will no longer be necessary or useful in the performance of any of its duties to the public.[116]

Commission Determination:

58 RCW 80.12.020(1) provides:

> [n]o public service company shall sell, lease, assign or otherwise dispose of the whole or any part of its franchises, properties or facilities whatsoever, *which are necessary or useful in the performance of its duties to the public*, and no public service company shall, by any means whatsoever, directly or indirectly, merge or consolidate any of its franchises, properties or facilities with any other public service company, without having secured from the commission an order authorizing it to do so. The commission shall not approve any transaction under this section that would result in a person, directly or indirectly, acquiring a controlling interest in a gas or electrical

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[113] McGuire, Exh. CRM-1T at 41:19-42:3; *see also* Kinney, Exh. SJK-3C.

[114] Dreyer, Exh. JMD-1CT at 9:1-3

[115] Public Counsel's Post Hearing Brief at 18 ⁋ 55.

[116] Kinney, Exh. SJK-11CT at 9:13-10:4.

> company without a finding that the transaction would provide a net benefit to the customers of the company.[117]

59 WAC Chapter 480-143 provides the Commission's regulations governing transfers of property. Section 480-143-120 states that:

> [a] public service company may not complete a transfer of property necessary or useful to perform its public duties unless the company first applies for and obtains, commission approval. Transfers include sale, lease, assignment of all or part of a public service company's property, and merger or consolidation of a public service company's property with another public service company.

60 Regarding a public service company's application for approval of an asset transfer, WAC 480-143-170 states that "[i]f, upon the examination of any application and accompanying exhibits, or upon a hearing concerning the same, the commission finds the proposed transaction is not consistent with the public interest, it shall deny the application."

61 Where a public service company is required to bring an agreement to the Commission for approval under RCW 80.12.020(1), and has failed to do so, the Commission "shall deny the application." As a result, when the Commission fails to provide any required approval of an asset transfer, the asset transfer agreement necessarily becomes void. However, RCW 80.12.020(1) makes clear that the requirement for Commission approval applies to the transfer of properties or facilities "which are necessary or useful in the performance of its duties to the public."[118]

62 Pursuant to CETA in RCW 19.405.030(1)(a), each electric utility must eliminate coal-fired resources from its allocation of electricity on or before December 31, 2025, such that the costs and benefits associated with coal resources are removed from the electric utility's retail customer rates.[119] As Staff witness McGuire points out in testimony, CETA defines "allocation of electricity" in RCW 19.405.020(1) as follows: "for the purposes of setting electricity rates, the costs and benefits associated with the resources used to provide electricity to an electric utility's retail electricity consumers that are located in this state [Washington]."[120]

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[117] RCW 80.12.020(1) (emphasis added).

[118] *Id*.

[119] *See* RCW 19.405.020(1).

[120] McGuire CRM-1CT at 34:1-10; RCW 19.405.020(1), 19.405.030(1).

63 During this proceeding, Avista updated its A&A Agreement to make transfer of its Colstrip ownership to NWE effective as of 12:00 AM Pacific Time, January 1, 2026. As such, Avista's transfer of its Colstrip ownership to NWE will occur after CETA's requirement to remove coal from the Company's allocation of electricity takes effect. While the A&A Agreement transfers Avista's ownership interest in Colstrip, it preserves Avista's Colstrip transmission rights.

64 In general, every transfer of property that is useful and necessary from a public service company to another entity is subject to Commission approval pursuant to RCW 80.12.020. However, by prohibiting the use of certain resources for service in Washington, CETA has a unique interaction with the transfer of property statute, insofar as CETA effectively makes certain generating resources neither necessary, nor useful, for service after a specific point in time. For coal-fired resources, that point in time is December 31, 2025.[121]

65 Consequently, the Commission determines that the A&A Agreement is not subject to Commission approval pursuant to RCW 80.12.020 because, at the time Avista's Colstrip ownership is transferred to NWE, Colstrip will not be "necessary or useful in the performance of [Avista's] duties to the public," other than the Colstrip transmission rights, which the Company has retained.

66 The Commission is cognizant of the fact that this conclusion is unique and unusual. However, as will be addressed elsewhere in this Order, the fact that the Commission is not reviewing the A&A Agreement for approval does not mean that the Commission will refrain from examining actions taken pursuant to the A&A Agreement under other Commission standards. The Commission's determination that the A&A Agreement is not subject to review because Colstrip's generation will not be necessary or useful in the performance of Avista's duties to the Washington public is consistent with RCW 19.405.030(3)'s requirement that coal-fired resources be removed from Avista's allocation of electricity. Moreover, the Commission is not without recourse to fashion alternative review mechanisms pursuant to its statutory duty to regulate in the public interest.[122]

67 In order to facilitate future review of the transfer of property that will become unable to serve Washington customers in the future due to the requirements of CETA, including

[121] RCW 19.405.030(1)(a).

[122] RCW 80.01.040.

but not limited to RCW 19.405.030-.050,[123] the Commission requires Avista to comply with the following condition:

> Going forward from the date of this Order, where Avista executes an agreement transferring assets for the purpose of complying with a requirement in CETA, Avista must file that agreement with the Commission for review and, if deemed necessary by the Commission, approval within five (5) days of entering into the agreement, even where the resource may no longer be necessary or useful in the performance of its duties to the public by operation of CETA. In its review of the agreement, the Commission will consider whether the agreement is consistent with the public interest and equity concerns of CETA.

68 The Commission intends Avista's compliance with this condition going forward to provide sufficient time for the Commission to review and take appropriate action within the scope of its regulatory authority, with input from the Company and interested parties, to ensure that agreements executed to comply with CETA do not contradict or undermine the goals and intent of CETA or result in consequences otherwise inconsistent with law.

69 Had Avista brought forward the A&A Agreement for Commission approval, considering the January 2023 execution date of the agreement, it would have afforded the Commission and the non-company parties considerable additional time leading up to the CETA deadline of December 31, 2025, to address the unique circumstances presented by RCW 19.404.030(1) and provide input on any other extant circumstances that may have appeared relevant to the transfer and how it may have impacted or benefitted customers.

70 For example, Avista appears to have executed the A&A Agreement, in which it agreed to vote consistent with NWE on any investments in Colstrip, despite Avista's earlier agreement in Avista's 2019 GRC settlement that Avista would "not support capital expenditures at Colstrip that go beyond routine capital maintenance costs that extend the plant's operational life beyond December 31, 2025."[124] The six other parties who joined

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[123] NWEC's Post Hearing Brief at 2 ⁋ 4 (discussing future decisions the Commission may be asked to make related to the treatment of fossil fuel generating resources that use fossil fuels other than coal and that are subject to CETA requirements in RCW 19.405.030); *see also* Staff Brief at 16 ⁋ 39; Avista Post Hearing Brief at 26 ⁋ 83-88; Supplemental Brief of Public Counsel at 4 ⁋ 5.

[124] *WUTC v. Avista Corp.*, Dockets UE-190334, UG-190335 and UE-190222 (*Consolidated*) Final Order 09, Approving and Adopting Partial Multiparty Settlement Stipulation Appendix A at 12-13 ⁋ 14(j) (March 25, 2020). *See also* Order 10 Granting Petition to Amend Final Order 09 to Reflect Modified Stipulation (December 14, 2020) (The Commission approved a proposed amendment to the settlement that was supported by all settling parties at Paragraph 14(d), which set a date for feedback from Avista's Energy Efficiency Advisory Group. No changes were made to ¶ 14(j).

and argued in support of the settlement presumably abandoned any litigation positions they otherwise may have pursued, and that may have influenced a Commission decision setting rates in the 2019 GRC, absent Avista's agreement not to pursue certain investments that extended the operating life of Colstrip.[125] The Commission further addresses the Settlement approved in Final Order 09 in Dockets UE-190334, et al., in Section IV of this Order.

71 As the Commission has determined that the A&A Agreement is not subject to approval under RCW 80.12.020, it is unnecessary to resolve the arguments regarding whether Avista could have operated its portion of Colstrip as a merchant plant. However, the Commission observes that Avista presented credible evidence that the Company faced financial and legal risks if it elected to operate Colstrip as a merchant plant, Avista had a difficult bargaining position with respect to Colstrip. Furthermore, insofar as CETA prohibits the cost and benefits from coal-fired resources from being included in retail electric customer rates, it is unclear how the operation of Colstrip as a merchant plant would have any direct or indirect value to Avista's Washington customers. There is no analysis in the record before the Commission regarding what those benefits could be, and the Commission will not presume that such benefits exist in the absence of supporting evidence. Finally, issues regarding decommissioning and remediation costs are not properly before the Commission in this case and will be reviewed in a later proceeding when such costs are proposed for inclusion in rates.

72 Finally, although RCW 80.12.020(1) does not apply to Avista's transfer of its Colstrip ownership interest in the A&A Agreement, the Commission clarifies that it applies a public interest standard in its review of agreements that are subject to RCW 80.12.020. While the Commission reviews utility investment decisions for prudence for the purpose of cost recovery, the Commission does not make prudence determinations when reviewing asset transfer agreements under RCW 80.12.020.

IV. Avista's Commitment in the 2019 GRC Settlement Not to Support Life-Extending Investments at Colstrip

73 Staff and NWEC have referenced Avista's participation in the Partial Multiparty Settlement that the Commission approved without condition in partial resolution of

[125] Dockets UE-190334 et. al., Final Order 09, Appendix A at 1 ⁋ 1 (The seven parties who joined the settlement were Avista, Staff, Public Counsel, AWEC, NWEC, The Energy Project, and Sierra Club.).

Avista's 2019 GRC Settlement.[126] All of the non-company parties in this docket also participated in Avista's 2019 GRC and supported the terms of the 2019 GRC Settlement in which Avista made commitments regarding how it would approach "life-extending" investments at Colstrip going forward. The relevant language is in paragraph 14.j of the 2019 GRC Settlement, beginning with the following:

> Avista agrees that it will not support capital expenditures at Colstrip that go beyond routine capital maintenance costs that extend the plant's operational life, beyond December 31, 2025. Capital costs associated with protecting human health and safety are generally acceptable to the Parties.

74 Paragraph 14.j also provides the settling parties' agreement regarding prudence determinations for Avista's capital expenditures at the Colstrip plant, including those related to SmartBurn:

> Avista recognizes and confirms that all Colstrip capital expenditures after December 31, 2017, will be subject to a prudence determination in future rate proceedings and Avista will provide detailed information, including a complete record of the decision making, and a full accounting of the costs related to those project expenditures on an annual basis. This means that Colstrip capital additions after December 31, 2017, are not included in Avista's rate base at this time."

75 The Commission approved these terms in Final Order 09, finding, based on the Joint Testimony, that the Settlement "represents a deliberate effort to align the plan for the recovery of Colstrip costs with the requirements of CETA," and that it "seizes the opportunity to find a solution for the remaining production plant balance for Colstrip, while mitigating intergenerational inequity issues."[127]

76 The Commission referenced the terms of Paragraph 14.j in Avista's 2020 GRC in disallowing recovery for Avista's dry ash project costs, which at the time were not known and measurable.[128] The Commission explained further that it was "uncertain that Dry Ash is not a life-extending capital addition."[129] The Commission did not view Dry Ash as a

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[126] Dockets UE-190334 et. al, Final Order 09.

[127] Dockets UE-190334 et. al, Final Order 09, at 20-21 ⁋ 54.

[128] *WUTC v. Avista Corp., d/b/a Avista Utils.*, Dockets UE-200900, UG-200901, and UE-200894 (*Consolidated*), Final Order 08/05 at 98-100 ⁋⁋ 275-279 (September 27, 2021).

[129] Dockets UE-200900 et. al., Final Order 08/05 at 100 ⁋ 279.

routine capital maintenance measure and, absent a sufficient showing by Avista that Dry Ash was not life-extending, the Commission was "unconvinced that it should be allowed in rates."[130]

77 Here, despite its agreement in the 2019 GRC Settlement not to support life-extending investments beyond 2025, Avista argues that it should recover "the full undepreciated value of the capital investments" it made in the Colstrip plant in 2024 and 2025. The investments offered for recovery in the initial filing include 73 capital projects, all of which have useful lives beginning in either 2024 or 2025 and extending to varying degrees beyond December 31, 2025, despite Avista's agreement in its 2019 GRC that it "will not support capital expenditures at Colstrip that go beyond routine capital maintenance costs that extend the plant's operational life, beyond December 31, 2025."[131]

78 Avista nevertheless asserts that that it did not "support" these 73 investments despite being subject to the O&O Agreement and maintains that it acted reasonably to avoid unnecessary investments even at the full value of capital investments.[132]

79 Avista argues further that:

> [i]t is not uncommon (indeed, it is to be expected) that the purchaser of an operating facility would insist on the delivery of the asset to be in good working order at closing (January 1, 2026); to that end, it is common-place for the purchaser to "direct" the voting of the seller to satisfy itself that the plant would be delivered in good working order, not only at closing but for the foreseeable future. No reasonable purchaser would allow the plant to be starved of needed capital investment in the meantime, so it has to somehow play catchup on needed investments for years to come.[133]

80 Additionally, Avista argues: (1) that the overall level of capital spending for 2024 and 2025 was consistent with prior years and was not trying to "load up" unnecessary capital investments to NWE's benefit in future years;[134] (2) that non-company parties were unable to demonstrate that the 2024 and 2025 investments were unnecessary for the

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[130] *Id*.

[131] *Id*.

[132] Avista's Post Hearing Brief at 9 ¶ 30.

[133] Avista's Post Hearing Brief at 10 ⁋ 31.

[134] Avista's Post Hearing Brief at 10 ⁋ 32.

ongoing operation of the plant; and (3) that Avista had a legal obligation to deliver the plant in good working order consistent with sound maintenance practices.[135]

81 Avista attempts to distinguish its agreement in the 2019 GRC Settlement to "not support" capital projects at the Colstrip plant that are life-extending beyond 2025, from its "voting" to support the investments consistent with NWE's direction under the A&A Agreement during the interim period between the January 2023 execution and the January 1, 2026 closing.[136] Avista differentiates its supporting votes in favor of the investments from its participation in budgeting, in which Avista states that it "did not lend 'support' (operative language of settlement) for projects that provided no value for Avista's customers."[137] To bolster its argument, Avista points to its efforts to pro-rate the share of dollars assigned to "long-lived enhancement work," reflected in Exhibit I to the AA Agreement, which allocates responsibility for outage and capital costs over time.[138]

82 While all the non-company parties in this docket oppose Avista's recovery of at least the portion of the life-extending capital expenditures attributable to services after December 31, 2025, NWEC and Staff also assert that because Avista violated the 2019 GRC Settlement, it should be prohibited from recovery of these amounts.[139]

83 NWEC points to the Commission's disallowance of Avista's Dry Ash Waste Disposal System in Avista's 2020 GRC as an indication of the Company's agreement to not support life-extending investments at Colstrip and argues that Avista has a duty to demonstrate that its investments in Colstrip are not life extending before it can recover those investments in rates.[140] NWEC asserts that if "a project's useful life and function materially extend Colstrip's ability to operate past December 31, 2025, it violates both the spirit and the letter of Avista's commitment in the 2019 Settlement," and "urges the Commission to give Avista's doublespeak little weight, use common sense, and conclude that voting for something is supporting it."[141]

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[135] Avista's Post Hearing Brief at 10 ⁋ 33

[136] Avista Post Hearing Brief at 18 ⁋ 54.

[137] Avista's Post Hearing Brief at 18 ¶ 55 (quotations included).

[138] Avista's Post Hearing Brief at 18 ¶¶ 55-56, Kinney, Exh. SJK-11CT at 30:14-18, 31:3-9 and AA Agreement Section 7.1(b)(iv)(B).

[139] Mullins, Exh. BGM-1CT at 2:12-18, 10:3-9; Dreyer, Exh. JMD-1CT at 4:1-21; Cebulko, Exh. BTC-1CT at 6:4-10, 27:3-14; McGuire, Exh. CRM-1CT at 40:6-11, 41:3-5, 42:15-43:17.

[140] NWEC's Post Hearing Brief at 3-4 ¶ 8.

[141] NWEC's Post Hearing Brief at 4-4 ¶¶ 9-12.

84 Staff also asserts that Avista bargained away the right to seek recovery of certain costs related to its Colstrip investments "by settling its 2019 general rate case, in part, by agreeing not to support capital expenditures at Colstrip that go beyond routine capital maintenance costs that extend the plant's operational life beyond December 31, 2025."[142] Staff also points to the Commission's reference to this term in its disallowance of Colstrip investments in 2020 where Avista failed to show sufficiently that its investments were not life extending.[143]

85 Staff cites the Merriam-Webster dictionary definition of "support" as "to argue or vote for." Staff asserts that Avista's commitment in the A&A Agreement constituted support for investments that extend the life of the Colstrip plant, contrary to Avista's commitment in the 2019 GRC Settlement that it would not support life-extending investments at Colstrip.[144]

86 Staff witness McGuire states that Avista now seeks recovery of "numerous investments in long-lived plant that appear to go well beyond recurring maintenance work."[145] Specifically, McGuire notes that of the 73 projects, 29 of them do not fit Avista's definition of recurring maintenance work, 25 of those have an expected service life of ten years or greater, and ten have an expected service life of 25 years or greater.[146]

Commission Determination

87 Avista's arguments regarding whether voting in support constitutes actual support focus more on whether Avista's investment decisions were prudent rather than whether those decisions were consistent with the 2019 GRC Settlement. Either way, there is no dispute that the text of the 2019 GRC Settlement states that Avista "will not support capital expenditures at Colstrip that go beyond routine capital maintenance costs that extend the plant's operational life, beyond December 31, 2025."[147]

88 Whether Avista's investments in the 73 projects at issue in this proceeding were in accordance with "standard operating procedure" or not, Avista made financial

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[142] Staff's Post Hearing Brief at 15 ⁋ 35.

[143] Staff's Post Hearing Brief at 15 ⁋ 35; McGuire, CRM-1CT at 10:14-11:8, 16:5-7, 37:5- (citing Avista 2020 GRC Order at 100 ⁋ 279).

[144] Staff's Post Hearing Brief at 5-16 ⁋ 37.

[145] McGuire, Exh. CRM-1CT at 29:5-6.

[146] McGuire, Exh. CRM-1CT at 38:20-39:1-6.

[147] McGurie, Exh. CRM-1CT at 40:9-11.

investments in, and thereby supported, the projects to ensure that Colstrip Units 3 and 4 were "delivered in good working order, not only at closing but for the foreseeable future." To the extent the foreseeable future extends beyond 2025, Avista has acted contrary to its agreement in the 2019 GRC Settlement.[148]

89 We presume Avista's commitment not to support capital expenditures in Colstrip beyond routine capital maintenance costs that extend the plant's operational life beyond December 31, 2025, factored in the decisions of six other parties to join the settlement in Avista's 2019 GRC and to abandon litigation positions that otherwise might have influenced the Commission's decision in that case. The Commission set rates in that case based on the joint support of the settling parties who relied on Avista's commitment not to support life-extending investments beyond the CETA deadline for the removal of coal-fired resources from Washington customers' allocation of electricity.[149] Absent an amendment to Final Order 09 in Dockets UE-190334 et.al., the terms of the 2019 GRC Settlement were in effect in January 2023 when the A&A Agreement was executed and remain in effect now and going forward.

90 However, because this docket concerns Avista's request to recover its investments in the Colstrip plant and is not a complaint for penalties that would have otherwise put Avista on notice of violations of the 2019 GRC Settlement, the Commission is not imposing penalties for any such violation in this Order.

V. Inclusion of 2025 Plant Additions Despite the "One-Year Lag" Language in Avista's 2022 GRC Settlement

91 Staff witness McGuire recommends that the Commission take action pursuant to WAC 480-07-370(3)(a) to "amend the Final Order of the Company's 2022 GRC and relieve Avista of the requirement under the Settlement that Avista include Colstrip plant additions in Schedule 99 rates on a one-year lag."[150] However, neither Staff nor any other party continues this recommendation on brief. As discussed below, we decline to amend Final Order 10/04, because both the Final Order 10/04 and the 2022 GRC Settlement include language that contemplates Avista's ability to recover 2025 Colstrip plant additions through a Colstrip Tracker Schedule 99 filing.

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[148] Final Order 09 Appendix A at 12-13 ⁋ 14(j).

[149] *See* Partial Multiparty Settlement Stipulation, Final Order 09, Appx. A at 1, ⁋ 1 (Mar. 25, 2025) (The seven parties who joined the settlement were Avista, Staff, Public Counsel, AWEC, NWEC, The Energy Project, and Sierra Club.); RCW 19.405.030(1).

[150] McGuire, Exh. CRM-1CT at 36:18 - 37:3.

92 The Commission approved the Colstrip Tracker and Tariff Schedule 99 in its resolution of Avista's 2022 general rate case (GRC) in Final Order 10/04 approving with conditions a Full Multiparty Settlement Stipulation (Settlement or 2022 GRC Settlement). The Colstrip Tracker is discussed in paragraph 14.b of that settlement, in which Avista agreed that "it would track all Colstrip costs other than transmission investment and costs included in Avista's Energy Recovery Mechanism including but not necessarily limited to O&M expense, depreciation expense, D&R costs, and return on rate base."[151]

93 All future Colstrip investments, including pro forma Colstrip investments that were included in the 2022 GRC, were to be recovered separately through this tracking mechanism, subject to review, including but not limited to an examination of prudence. Under the 2022 GRC Settlement, the review of Colstrip investments proposed for inclusion in this mechanism will occur through Avista's annual tariff revision for the Colstrip tracker for separate ratemaking treatment.

94 In the Joint Testimony supporting the Settlement, parties stated that for recovery of any unrecovered Colstrip net rate base costs after December 31, 2025, "the Company will have an opportunity in a future proceeding or Tariff Schedule 99 Compliance filing to propose recovery of any unrecovered balances deemed prudent by the Commission as of December 31, 2025, that still allows the Colstrip balances to be removed as required at December 31, 2025."[152]

95 The Joint Testimony explains that the Colstrip Tracker would be administered through Tariff Schedule 99 with the initial rate effective date of December 21, 2022, concurrent with the 2022 GRC, and would be reset each January 1st thereafter, via a filing made each October 31st *until all prudently incurred costs are recovered*.[153] Prudency of the incurred costs would be reviewed in each year's annual filing, and the tracker would recover non-O&M items "on a one-year lag, using actuals through August 31st and estimates through December 31st of the filing year" and "[a]mounts that were included in Schedule 99 on a forecast basis will be trued-up to actuals in each annual tariff filing."[154]

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[151] Settlement at 6-7, par 14b (citing 2019 PSE GRC Final Order 08/05/03, Dockets UE-190529, UG-190530, UE-190274, UG-190275, UE-190991, AND ug-190992 (*consolidated*), at par. 388 & 425 (discussing why Staff believes a tracking mechanism is the appropriate way to recover these costs).

[152] Staff Response to Bench Request No. 1, Attachment A, Supplemental Joint Testimony, JT-3T at 12:20-24.

[153] JT-3T at 6:7-10 (emphasis added).

[154] JT-3T at 6:20-21

96 In addition, the Joint Testimony states that "[e]xcept for costs associated with regulatory assets and liabilities, all costs for Colstrip capital investment and operating expenses will be removed from Tariff Schedule 99 and customer rates effective January 1, 2026, per the Clean Energy Transformation Act ("CETA")." This discussion references the CETA deadline in RCW 19.405.030(1)(a), which requires:

> [o]n or before December 31, 2025, each electric utility must eliminate coal-fired resources from its allocation of electricity. This does not include costs associated with decommissioning and remediation of these facilities.[155]

97 That Avista would recover Colstrip plant investments on a "one-year lag" is also stated in the illustration that appears in the Joint Testimony Exhibit JT-3T and Exhibit JT-4.[156] As Staff witness Chris McGuire explains, "2023 rates would include plant additions through 2022, 2024 rates would include plant additions through 2023, and 2025 rates would include plant additions through 2024." For 2026, however, the December 31, 2025, CETA deadline appears to disallow utility recovery of costs for coal-fired resources from Washington customer rates.[157]

98 To address recovery of 2025 plant additions despite CETA's December 31, 2025, coal-fired resource deadline, the settling parties state in Exhibit JT-3T that to recover Colstrip net rate base costs after December 31, 2025, "the Company will have an opportunity in a future proceeding or Tariff Schedule 99 Compliance filing to propose recovery of any unrecovered balances deemed prudent by the Commission as of December 31, 2025."[158]

99 Final Order 10/04 acknowledges this cost recovery on a one-year lag, but also recognizes the CETA requirement "to remove the total costs for Colstrip capital investment and operating expenses, excluding Colstrip transmission investments and ongoing D&R costs from customer rates after December 31, 2025," referencing the Joint Testimony discussion of the opportunity to recover the unrecovered balances deemed prudent by the Commission as of December 31, 2025. Final Order 10/04 also states that "beginning

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[155] RCW 19.405.030(1)(a).

[156] JT-4; JT-3 at 7:1-9.

[157] RCW 19.405.030(1)(a).

[158] JT-3T at 12:20-24.

January 1, 2026, the Colstrip Tracker will include only annually updated ongoing D&R net rate base balances and Colstrip Regulatory amortization expense."[159]

Commission Determination:

100 Staff witness McGuire discusses possible confusion between the CETA December 31, 2025, deadline, the one-year lag language in the 2022 GRC Settlement, and in certain paragraphs of Final Order 10/04. However, the Commission determination language of Final Order 10/04 does not disallow recovery of 2025 plant additions or otherwise restrict Avista's recovery of those costs to a "one-year lag" that would be impossible to implement by virtue of CETA. Accordingly, no party argues on brief in this docket that an amendment is required, and we do not view Avista's recovery of prudently incurred used and useful 2025 plant additions as a violation of the 2022 GRC Settlement, or Final Order 10/04.

VI. Investments in Colstrip

101 In its October 31, 2024, initial Tariff Schedule 99 filing, Avista requested a rate increase of approximately $18.2 million, or 2.7 percent, for recovery of 2024 and 2025 costs associated with Colstrip Units 3 and 4, and allocated $10.9 of the $18.2 million in plant additions to Washington.[160] However, on rebuttal Avista revised its position "to include approximately $12.0 million in system-wide Colstrip plant investments for 2024 and 2025,"[161] and effectively reduced its Washington's share of plant additions from $10.9 to 7.7 million.[162]

102 In response, Staff, AWEC, and NWEC proposed Colstrip 2024 and 2025 capital investment recovery amounts of $5.6 million, $3.0 million, and $1.98 million respectively, as illustrated in Table 1 and discussed in further detail below.[163]

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[159] *Wash. Utils. Transp. Comm'n v. Avista Corp., d/b/a Avista Utils.*, Dockets UE-220053, UG-220054, and UE-210854 (consolidated) (Avista 2022 GRC) Final Order 10/04 at 23, ⁋ 66 (Dec. 12, 2022).

[160] Kinney, Exh. SJK-1T at 7:11-13 and SJK-9C. Of the $10.9 million, $3.2 million is attributed to 2024 plant additional and $7.7 million to 2025 plant additions. Kinney, Exh. SJK-8C (2024 Capital Budget) and SJK-8C (2025 Capital Budget).

[161] Avista's Post Hearing Brief at 3 ¶ 7.

[162] Avista's Post Hearing Brief at 2 ¶ 5 and Andrews, Exh. EMA-1CT at 2:5-10.

[163] Avista's Post Hearing Brief at 2 ¶ 6.

103 Staff separated its analysis of the 73 capital expenditures at issue in this proceeding into six categories, recommending that "the Commission disallow recovery of all, or a portion of 25 of the 73 projects."[164] The 73 capital expenditures at issue consist of:

(1) 6 SmartBurn projects;[165]
(2) 3 projects not likely to go into service in 2025;
(3) 16 long-lived assets, which have longer useful lives than four years;
(4) 21 routine maintenance projects;
(5) 11 human safety projects; and
(6) 16 de minimis costs.

104 Staff did not contest the last three of those categories but did recommend disallowing all or portions of the others.[166] NWEC categorizes the projects similarly to Staff,[167] but treats the majority of the projects it disputes as long-lived assets with two of the projects that Staff categorized as de minimis, as intending to promote human safety. Unlike Staff who states that there are a total of 11 human safety projects, NWEC maintains there are a total of 13.[168] Specifically, NWEC recommends disallowing recovery of the first three categories and allowing a pro rata share of cost recovery for major maintenance, and full recovery of the 13 human safety projects.[169] Conversely, AWEC and Public Counsel recommend "prorating all capital additions based on their useful life," with in-service dates prior to December 31, 2025,[170] and do not contest the inclusion of the 13 human safety projects' allowance in rates. While Public Counsel did not provide a specific breakdown of the amounts that Avista should be allowed to recover, Public Counsel

[164] McGuire, CRM-1CT at 3:6-7.

[165] Avista's six 2024 and 2025 capital investment projects related to SmartBurn are:(1) Separate Over Fire Air (SOFA) Bucket Replacement (U3) system; (2) Boiler Burner Aux Air Replacement U3; (3) Top Over Fire Air (TOFA) Bucket Replacement U3; (4) Boiler Burn Aux Air Replacement U4; (5) SOFA Bucket Replacement U4; and (6) TOFA Bucket Replacement U4.

[166] Staff's Post Hearing Brief at 2 ¶ 5 and footnote 3, and McGuire, CRM-1CT at 3:8-13. Specifically, "Staff did not contest Avista's request to recover routine maintenance costs, based on Staff's reading of Avista's 2019 GRC Settlement…which imply that Avista may recover routine, "non-life extending assets." Additionally, Staff did not contest the 16 de minimis projects because they did not materially impact rates or the recovery of the human safety projects because the benefits justified the costs. *See also* McGuire, Exh. CRM-1CT at 6:10, and 6:19-7:10.

[167] Cebulko, BTC-1CT at 19:10-15.

[168] Cebulko, BTC-1CT at 35:13-22 and 36:1-3 (Table 6).

[169] Cebulko, BTC-1CT at 3:8-14.

[170] Dreyer, Exh. JMD-1CT at 3:11-14 and JMD-2T at 3:6-18 citing to Mullins, Exh. BGM-1T at 11:18-20.

agrees with AWEC's proposed approach of "prorating all 2024 and 2025 capital additions based on their useful life," with in-service dates prior to December 31, 2025.[171]

105 To provide an overview of each of the parties' proposals for recovery of Colstrip capital investments in rates, we have incorporated the table below, which has been adapted from Avista's redacted rebuttal testimony,[172] and cross-referenced each party's responses and cross-answer testimony.

Table 1 –2024 and 2025 Investment – Summary of Positions[173]

2024 and 2025 Capital Investment Proposals by Party (in millions)					
	Avista Revised[174]	**Staff**	**AWEC**	**NWEC**	**Public Counsel**
	10,802	**10,932**	**10,932**	**10,932**	(1)
SmartBurn	(65)	(578)		(641)	
Long-Life (Pro-Rate to NWE or Remove)	(1,171)	(2,892)	(7,914)	(6,436)	
Not Used and Useful (Remove)	(1,824)	(1,873)		(1,873)	
Total to Remove	(3,060)	(5,343)	(7,914)	(8,950)	
Proposed Recovery	**7,742**	**5,589**	**3,018**	**1,982**	
Difference between Proposals		(2,153)	(4,724)	(5,760)	
(1) Public Counsel did not provide a breakdown of their proposal.					

106 As illustrated above in Table 1, Avista's revised position for Colstrip 2024 and 2025 Capital investments includes recovery in Schedule 99 for calendar year 2025, totaling $7.7 million. The $7.7 million revised amount is comprised of "a $4.8 million reduction

[171] Dreyer, Exh. JMD-1CT at 3:11-14 and JMD-2T at 3:6-18 citing to Mullins, Exh. BGM-1T at 11:18-20.

[172] Andrews, Exh. EMA-1CT at 13:1-8.

[173] See Table 2, excerpted from Kinney, SJK-11CT at 23:1-9 and Table 6, Andrews, EMA-1CT at 13:1-8.

[174] Avista notes that there were minor differences in the "As-filed" amount of $10.8 million based on estimated as-filed monthly transfers to plant of 2024 and 2025 additions and that the "As-field" amount of $10.9 million reflects detailed balances by project provided with the Company filing. *Id*.

in total system investments," and "a $3.1 million decrease in Washington's share,"[175] and "reflects the removal of three general categories of disputed investments, including: (1) the removal of $65,000 in SmartBurn-related investments mistakenly included in the Company's initial filing; (2) $1.2 million of investment prorated to NWE; and (3) $1.8 million in investment deemed not used and useful by December 31, 2025, and assigned to NWE."[176] Accordingly, if the Commission were to exclude the 2024 and 2025 capital investments proposed by Staff and the other parties, Avista maintains that the portions of investments removed "would require an immediate write-off on Avista's books of record in 2025, ranging between $2.2 million (Staff) to $5.8 million (NWEC)," which would adversely impact the Company's actual earnings and credit rating. [177]

107 To demonstrate that it has met its burden to recover its 2024 and 2025 Colstrip capital investments, Avista focuses its arguments on the four factors the Commission typically considers when determining prudency, and addresses to a lesser degree how the Company's capital additions satisfy the used and useful standard.[178] In addition, each of the other parties' arguments do not necessarily distinguish clearly between the concepts of prudence and used and useful. Despite the parties' intermingling of these concepts in testimony and briefing, the Commission will first consider how each party addresses the requirement that the capital project investments for which a utility company request cost recovery are used and useful for service to Washington customers.

A. Used and Useful

108 As mentioned above, the Company does not discuss how its Colstrip investments meet the Commission's used and useful standard with the same level of particularity as it does in its prudence arguments.[179] Specifically, Avista argues that its Colstrip investments at issue in this docket are necessary to maintain safe and reliable operation of Colstrip Units 3 & 4 for the benefit of Avista's customers.[180] Avista further discusses the regular

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[175] Andrews, Exh. EMA-1CT at 7:7-9.

[176] Andrews, EMA-1CT at 7:16-18 and 8:1-2.

[177] Andrews, EMA-1CT at 3:27-28. 4:1-4 and 13:9-12.

[178] The four factors include the: (1) Need for the Resource; (2) Evaluation of Alternatives; (3) Communication with and Involvement of the Company's Board of Directors; and (4) Adequate Documentation as set forth the Commission's Standard for Prudence.

[179] Kinney, Exh. SJK-1T at 4:1-2.

[180] Kinney, Exh. SJK-1T at 2:1-2.

periodic maintenance of the plant in the context of the cost-benefit considerations Avista considered when making the investments.[181]

109 To support its contention that customers benefit from the lower power supply costs enabled by these investments, Avista argues that without operation of Avista's Colstrip Units 3 and 4, system power costs would have been at least $84.2 million, or nine percent higher than what was included in its 2024 GRC compliance filing that set rates for 2025. Avista also contends that this does not include the cost of replacing Colstrip's contribution to Avista's capacity and reliability requirements that would have added an additional $120.5 million, system-wide.[182] Avista further explains that the investments "were necessary to address reliability and safety of Colstrip from the time they are installed through their end of life," but acknowledges that "Avista's customers have and will continue to receive the benefit of energy generated by Colstrip through" and "until the end of 2025."[183] For these reasons, Avista maintains that the capital projects at issue are used and useful as follows.

Projects that May Not be In Service and Used and Useful Before the End of 2025

110 First, Avista requests recovery of three specific projects for which the in-service dates have been "in flux."[184] These include: (1) the U4 Generator Exciter; (2) the North Cheyenne AAQ system; and (3) the Baghouse. On rebuttal, Avista acknowledges that the Baghouse project will not be in-service in 2025 and removes its request to recover the $65,000 in costs for this project.[185] However, Avista seeks a pro rata recovery of four percent of the costs incurred for the U4 Generator Excitor based on the A&A Agreement it entered into with NWE, in which the remaining 94 percent was apportioned to NWE.[186] Avista also seeks full recovery of the Northern Cheyenne AAQ system, and it contends that both of these projects will be completed in October 2025 and are necessary projects to continue operating the plant in 2025.[187]

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[181] Kinney, Exh. SJK-1T at 7-8.

[182] Kinney, Exh. SJK-1T at 13:1-9.

[183] Kinney, Exh. SJK-1T at 11:16-21, 13:17-18, 15:15-22, 17:14-21.

[184] Kinney, Exh. SJK-11CT at 18:2-4; *See also* Mullins, Exh. BGM-1CT at 10:10-18; McGuire, Exh. CRM-1CT at 9-11.

[185] Kinney, Exh. SJK-11CT at 18:2-4; *see* Mullins, Exh. BGM-1CT at 10:10-18; McGuire, Exh. CRM-1CT at 9-11.

[186] Avista's Post-Hearing Brief at 17 ¶ 51 and Kinney, Exh. SJK-11CT at 28:2-6.

[187] Kinney, Exh. SJK-11CT at 28:4-7.

111 In response, Staff, Public Counsel, NWEC, and AWEC accept Avista's rebuttal position on the Baghouse project, given that this investment does not qualify for recovery and will not go into service until after December 31, 2025.[188] However, with respect to the other two projects, Staff recommends the Commission only allow Avista to recover a prorated share of the U-4 Generator Excitor and North Cheyenne System "because their useful lives will exceed Colstrip's four-year routine maintenance cycle."[189] Similarly, Public Counsel[190] and AWEC [191] recommend that the Commission prorate these capital additions based on their useful life and only provide Avista recovery for the portion in service prior to December 31, 2025.[192] NWEC continues recommending that the investments be denied on the basis that they explicitly extend the life of the plant.[193]

Routine Maintenance and Long-Lived Asset Projects

112 As for the 21 routine maintenance projects and 16 long-lived assets,[194] Avista argues that the Commission should reject NWEC's proposal to prorate routine maintenance and disallow long-lived assets and instead adopt the Company's and Staff's position[195] to allow recovery of the 21 routine maintenance projects.[196] Avista explains that "Colstrip major maintenance projects operate at a cycle that years of experience by plant staff have found meet efficient and safe operating cadence."[197] Avista also argues that the Company's agreement in the 2019 GRC Settlement not to support investments at Colstrip beyond routine capital maintenance and that extend the plant's operational life beyond

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[188] Staff's Post Hearing Brief at 5 ¶ 12, Public Counsel's Post Hearing Brief at 22-23 ¶ 68, NWEC's Post Hearing Brief at 2 ¶ 5, Cebulko, BTC-1CT at 25:8.

[189] Staff's Post Hearing Brief at 5 ¶ 12.

[190] Public Counsel Post Hearing Brief at 22-23 ¶ 68.

[191] Mullins, Exh. BGM-1CT at 10:17-18.

[192] Mullins, BGM-1CT at 11:18-21 and Mullins, Exh. BGM-3C.

[193] Cebulko, BTC-1CT at 25:7-9 and BTC-5C (Avista's Response to NWEC DR 016, Attachments A and B).

[194] Kinney, Exh. SJK-1T at 8:17-18 citing to McGuire, CRM-1CT at 15:12-15, and McGuire, Exh. CRM-2C.

[195] McGuire, Exh. CRM at 9-11 and CRM-2C at 2:28-48. Staff categorizes 21 projects as routine maintenance, which it defines as needing to be replaced every four years or less, and maintains that since "routine capital maintenance costs as Colstrip are generally accepts it does not dispute recovery of these projects.

[196] Avista's Post Hearing Brief at 17 ¶ 52 and Kinney, Exh. SJK-11CT at 29:1-4.

[197] Kinney, Exh. SJK-11CT at 29:1-17.

December 31, 2025, meant only that it would not support capital projects, but did not apply to "voting per se."[198]

113 To further bolster the argument that it did not support long-lived assets that did not benefit Washington customers, Avista argues that it challenged "the allocation of dollars assigned to long-lived enhancement work, so as to only accept a smaller, pro-rated share of the items that would otherwise extend the useful lives of the Project beyond 2025," and successfully apportioned certain long lived costs to NWE.[199] Avista argues that this process was successful because it was able to garner NWE's agreement and support to reduce Avista cost responsibility of several 2024 and 2025 capital expenditures as well as the proration of long lived assets, effectively allocating $1.17 million of the Washington share of costs away from Avista to NWE, and reducing the Company's overall requested capital down from $10.8 million to $7.7 million.[200]

114 Staff recommends that the Commission prorate the costs associated with Avista's 16 long-lived projects that represent investments in long-lived plant, which it argues Washington ratepayers will not benefit from beyond December 31, 2025.[201] Staff defines '*long-lived*' "as an asset with an expected service life greater than four years, which distinguishes those assets from routine maintenance projects."[202] Staff asserts that while the investments provide some benefit to Washington customers, the investments will not be able to provide the full benefit associated with their respective useful lives due to CETA's prohibition on coal power in Avista's allocation of electricity.[203] For support, Staff refers to the Commission's final order in Avista's 2020 GRC, where the Commission rejected Avista's request to recover costs of its Dry Ash Disposal Project because Avista had not shown that the project was not life-extending.[204] Staff maintains that because CETA prohibits coal in the Company's allocation of electricity beginning in

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[198] Avista's Post Hearing Brief at 18 ¶¶ 53-54 citing Dockets UE-190334 et.al., Final Order 09 Appendix A at 12-13 ⁋ 14(j) (March 25, 2020).

[199] Avista's Post Hearing Brief at 18 ¶ 55 and 19 ¶ 58 citing to Kinney, Exh. SJK-14C, Long Lived Assets with NWE.

[200] Avista's Post Hearing Brief at 20 ¶ 60, and Kinney, SJK-11CT at 4-6. See also Table 1 at ¶ 95 of this Order.

[201] McGuire, Exh. CRM-1CT at 3:12-13, 11:18-20.

[202] McGuire, Exh. CRM-1CT at 15:4-5. See McGuire, Exh. CRM-2C at 2:58-73 for the 16 long-lived plant additions Staff is contesting in this case.

[203] McGuire, Exh. CRM-1CT at 15:21-22, 16:1-7.

[204] Staff's Post Hearing Brief fn. 3 (*citing WUTC v. Avista Corp*., Dockets UE-200900 et. al., Order 08/05 at 100 ¶ 279.

2026, the Company should only be authorized to recover a proportional share of costs associated with long-lived assets because they will only benefit Washington customers for a portion of their overall useful life.[205]

115 NWEC argues that the Commission should prorate Avista's recovery based on the portions of the investments that are used and useful from the perspective of Washington customers considering CETA's timelines and disallow the portion of useful life extending past December 31, 2025.[206] NWEC cites Commission precedent that utilities generally cannot require their ratepayers to pay for investments unless they are used and useful, which requires a showing that an investment provided a benefit to Washington ratepayers either directly, such as through the flow of power from a resource to customers, and/or indirectly such as the reduction of cost to Washington customers through exchange contracts or other tangible or intangible benefits.[207] NWEC argues that because Avista ratepayers will not benefit from Colstrip's operation beyond December 31, 2025, they cannot be required to pay for Colstrip's long-term operation.[208]

116 Public Counsel argues that investments in Colstrip Units 3 and 4 will not be used and useful to Washington ratepayers after December 31, 2025, and that costs associated with capital additions related to Colstrip operations after that date must be excluded from rates.[209] Public Counsel further argues that requiring "Washington ratepayers to subsidize coal-fired power for customers in Montana or elsewhere violates the statutory used and useful standard, defeats the purpose of CETA," and "belies the…[Commission's] directive to regulate in the public interest."[210] To support its contention that there is no direct benefit of operating Colstrip facilities to Washington customers after December 31, 2025,[211] Public Counsel further asserts that including costs associated with Colstrip capital assets in service beyond 2025 will result in rates that are not fair, just, reasonable, and sufficient because Washingtonians will be unable to attain any value or benefit from the investments and will be harmed from an economic and environmental perspective by the inclusion of these investments in rates, which are contrary to the "letter and spirit" of

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[205] Staff's Post Hearing Brief at 21-22 ¶ 53.

[206] NWEC's Post Hearing Brief at 2 ⁋ 4 and 13 ⁋ 31.

[207] NWEC's Post Hearing Brief at 2-3 ⁋ 6 (citing *Wash. Utils. & Transp. Comm'n v. PacifiCorp., PacifiCorp, d/b/a Pacific Power & Light Co.*, Dockets UE-050684 & UE-050412, Order 04/03, ¶ 50 (Apr. 17, 2006)).

[208] *Id.*

[209] Public Counsel's Post Hearing Brief at 14 ¶ 44

[210] Public Counsel's Post Hearing Brief at 1-2 ¶ 4.

[211] Public Counsel's Post Hearing Brief at 3 ¶ 10

CETA.[212] Finally, Public Counsel maintains that Avista has not presented any evidence that allowing only a prorated portion of its Colstrip capital additions into rates will result in insufficient revenue for the Company to continue operating.[213] Therefore, Public Counsel recommends the Commission allow recovery of Avista's capital investments on a prorated basis so that Avista customers "only pay for a share of each plant addition proportional to their share of that plant addition's expected service life."[214]

117 Similarly, AWEC expresses concerns of Avista's request for "cost recovery of life extending investments," in the plant "that do not benefit Avista's ratepayers," and emphasizes that NWE "should be obligated to pay a fair value for that share, including reimbursement for the value of capital additions made by Avista that will benefit its customers."[215] AWEC requests that the Commission "reaffirm its used and useful standard as part of this proceeding,"[216] and recommends "disallow[ing] recovery [of] the portion of all capital investments with a depreciable life beyond December 31, 2025, attributable to service after that date, consistent with the cost recovery requirements that plant included in rates be both used and useful and prudent."[217] Finally, AWEC requests that Avista be required to "create a regulatory liability for any over-collection from customers" and be ordered to refund any over-collected amounts "[i]f actual in-service dates are December 31, 2025, or later…consistent with Avista's compliance filing proposal."[218]

De Minimis Projects

118 Avista requests to recover the 14 projects that Staff deems "de minimis" and having an immaterial impact on rates. NWEC, AWEC, and Public Counsel argue that the Commission should apply the used and useful standard and prorate Avista's recovery of

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[212] Public Counsel's Post Hearing Brief at 18-19 ¶¶ 57- 58.

[213] Public Counsel's Post Hearing Brief at 19 ¶ 59.

[214] Public Counsel's Post Hearing Brief at 24 ¶ 72.

[215] Mullins, Exh. BGM-1CT at 2:12-18.

[216] AWEC's Post Hearing Brief at 9-10 ¶ 19 citing to Dockets UE-050684, UE-050412, and UE-060669 (Consolidated), Order 06/05/02 at ¶ 15 (July 14, 2006) (recommending the Commission continue to interpret plant to be 'used and useful' when it benefits ratepayers in Washington either directly or indirectly.

[217] Mullins, Exh. BGM-1CT at 3:7-8 and 3:11-14. See also Mullins, Exh. BGM-3 in support of its recommended 2024 and 2025 reductions to capital.

[218] Mullins, Exh. BGM-1CT at 10:21, 11:1 and 11:3-5 citing to Mullins, Exh. BGM-4, Avista's Response to Staff's Data Request No. 12.

these project costs corresponding to the portion of the useful lives during which they were used and useful to Washington customers.

Human Health & Safety Projects

119 Avista requests recovery of 13 human health and safety projects in its initial filing. The non-company parties do not contest recovery of these projects. Staff witness McGuire discusses the extent of health benefits of these projects conferred on ratepayers versus the costs of the investments. NWEC cites the 2019 GRC Settlement language in which the settling parties agreed that capital costs associated with the protection of human health and safety are generally acceptable.[219]

Commission Determination:

120 RCW 80.04.250 provides, in relevant part, that:

> The commission shall have power upon complaint or upon its own motion to ascertain and determine the fair value for rate making purposes of the property of any public service company used and useful for service in this state by or during the rate effective period and shall exercise such power whenever it deems such valuation or determination necessary or proper under any of the provisions of this title.

121 When calculating a utility's rate base for ratemaking, if the Commission determines that the utility plant "is neither employed for service nor capable of being put to use for service…such a plant is not 'used and useful' for service."[220] In interpreting the phrase "used and useful," the Washington State Supreme Court has explained "'Used' is defined as 'employed in accomplishing something;' 'useful' is defined as 'capable of being put to use: having utility: advantageous: producing or having the power to produce good: serviceable for a beneficial end or object.'"[221] The Court further explained "RCW 80.04.250 empowers the Commission to determine, for ratemaking purposes, the fair value of property which is employed for service in Washington *and* capable of being put to use for service in Washington."[222]

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[219] Cebulko, Exh. BTC-1CT at 23:18-27 (citing Final Order 09 at Appendix A ⁋ 14.j.

[220] *POWER*, 104 Wn.2d at 815.

[221] *POWER v. State Utils. & Transp. Com*, 101 Wn.2d 425, 430 (1984) (*citing Webster's Third New International Dictionary* 2524 (1976)).

[222] *POWER v. State Utils. & Transp. Com*, 101 Wn.2d 425, 430 (1984).

122 By extension, "[w]hen calculating a utility's rate base for ratemaking, if the WUTC considers utility plant that 'is neither employed for service nor capable of being put to use for service; . . . such plant is not 'used and useful' for service' and the [Commission] exceeds its statutory authority."[223] The Commission has also previously interpreted "the phrase 'used and useful for service in this state' to mean providing benefits to ratepayers in Washington, either directly (e.g., flow of power from a resource to customers) and/or indirectly (e.g., reduction of cost to Washington customers through exchange contracts or other tangible or intangible benefits)."[224]

123 CETA states in RCW 19.405.030(3) that the Commission must allow in rates directly or indirectly, amounts on an investor-owned utility's books of account that the commission finds represent *prudently* incurred undepreciated investment in a fossil fuel generating resource that has been retired from service . . . ."[225]

124 The presence of "prudently incurred" in this section of CETA, coupled with the absence of "used and useful" calls into question whether the Washington Legislature might have intended for the Commission to dispense with the used and useful standard in applying that section of CETA. However, critically, in the same bill in which the Legislature enacted CETA in 2019, the Legislature revised RCW 80.04.250, affirming the used and useful standard. The Commission concluded in the Used and Useful Policy Statement that CETA did not alter the used and useful standard.[226] Therefore, we continue to apply the used and useful standard here: the Commission has determined utility property to be "used and useful" when it provides a benefit to ratepayers in Washington, either directly or indirectly.[227]

125 Given that CETA requires that Avista remove the benefits and costs of coal power from its retail customer rates no later than December 31, 2025, the Commission finds that any costs associated with investments in Colstrip based on benefits that are realized after

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[223] *Office of the Atty. Gen., Pub. Counsel Unit v. Wash. Utils. & Transp. Comm'n*, 4 Wn. App. 2d 657, 682 (2018) (quoting *POWER v. State Utils. & Transp. Com*, 101 Wn.2d 425, 430 (1984)).

[224] *WUTC v. PacifiCorp*, Dockets UE-050684 & UE-050412 (*consolidated*), Order 04/03 at 21-22 ¶ 50 (Apr. 17, 2006).

[225] RCW 19.405.030(3) (emphasis added).

[226] *In the Matter of the Commission Inquiry into the Valuation of Public Service Company Property that Becomes Used and Useful after Rate Effective Date*, Docket U-190531, Policy Statement on Property that Becomes Used and Useful After Rate Effective Date (January 31, 2020) at 4 ¶ 5 citing LAWS of 2019, Ch. 288 § 20(3) (January 31, 2020).

[227] *Id.*

December 31, 2025, must be excluded from rates by prorating Avista's recovery of costs based on the portion of their useful lives in service prior to the CETA deadline. Such approach appropriately removes coal power from Avista's allocation of electricity while assigning fair and equitable costs to ratepayers relative to the benefits received from the Colstrip investments.

126 Accordingly, for 57 of the 73 capital expenditures at issue, the Commission allows Avista to recover an amount prorated by the percentage of the useful life of each project during which that project was used and useful to Washington customers on or before December 31, 2025. As we discuss more fully below, we disallow three projects, two of which are the TOFA Bucket Replacement projects U3 and U4, and the third, the Baghouse project, which Avista affirmatively removed from its request on rebuttal, which will not be in-service before the CETA December 31, 2025, deadline. Lastly, we allow full recovery in rates for the 13 Human Safety projects.

127 Of the 73 total projects for which Avista seeks recovery for 2024 and 2025, we allow prorated recovery for the following 57 projects:

(1) 4 of the SmartBurn projects, which include the SOFA Bucket Replacement U3 and U4 projects and the Boiler Burner Aux Replacement U3 and U4 systems;

(2) 2 of the three projects which may go into service in 2025, including the U4 Generator Exciter and Northern Cheyenne AAQ;

(3) 16 Long-Lived Asset Projects;

(4) 21 Major Maintenance Projects; and

(5) 14 De Minimis Projects

1. Disallowing the Two TOFA Bucket Replacement U3 and U4 Projects and Prorating the Four Remaining SmartBurn SOFA and Boiler Aux Projects

128 As discussed above, we disallow the two TOFA Bucket Replacement U3 and U4 projects, which Avista affirmatively removed from its request on rebuttal. The remaining four SmartBurn projects for which Avista seeks recovery were in rates prior to Avista's 2020 GRC. As explained in subsection VI.B. below, we view those projects as prudently incurred and allow Avista to recover a prorated amount corresponding to the percentage of the useful lives of these projects that were in service and used and useful to customers on or before December 31, 2025.

2. Proration of Two Projects that May Go into Service Before 2025: Disallowance of the Baghouse Project

129 We disallow recovery of the Baghouse project because it will not be in-service before the end of 2025, a fact that Avista acknowledges in its rebuttal testimony. However, for the Generator Exciter-U4 project for which Avista seeks a 4 percent recovery and the Northern Cheyenne AAQ system, which Avista claims will be in service in October 2025, we expect Avista to provide documentation in its compliance filing in response to this Order demonstrating the actual in-service dates for these projects.

130 Based on the documentation Avista provides in its compliance filing, we will allow Avista to recover the prorated amount based on the percentage of the useful lives of these two projects that were in service and used and useful to customers on or before December 31, 2025. We note that the Commission would not ordinarily keep the record open to confirm in-service dates, but we do so here due to the unique and novel circumstances of this docket relating to the CETA requirement to remove coal-fired resources from Washington rates by the end of 2025.

3. Routine Maintenance and Long-Lived Asset Projects

131 Given the benefits conferred to ratepayers by the 21 routine maintenance and 16 long-lived asset projects that were in service before December 31, 2025, we concur with Staff, AWEC, and Public Counsel that Avista should be allowed to recover the prorated amount corresponding to the percentage of the useful lives of these investments that were in service on or before December 31, 2025.

4. De Minimis Projects

132 Consistent with our decisions above on other projects, we allow Avista to recover a prorated amount corresponding to the percentage of the useful lives of the 14 de minimis projects that were in service and used and useful to customers on or before December 31, 2025.

5. Human Health & Safety Projects

133 For the projects that relate to human health and safety, the Commission agrees with Staff and NWEC that these projects "provide near term human health benefits that exceed the costs of the investments," and therefore Avista should recover these projects in full.[228] The Company's ratepayers benefit from reasonable human safety investments that reduce the Company's risk of liability in the event of an incident resulting in injury or death to plant workers. Absent such investment, investors may be led to perceive the Company as relatively riskier, which could in turn require a greater degree of compensation to investors to account for that risk, thereby increasing overall future rates to customers.[229] Although utilities must transition away from certain resources to comply with CETA, the Commission does not want to create an incentive for utilities to avoid reasonable safety investments for such resources that place workers in threat of harm, which generally would be contrary to the public interest.[230] The Commission has no desire to see the transformation of Washington's energy supply to clean energy built upon a foundation of unnecessary hazards and risk of harm to workers.

B. Prudence

134 Now turning to Avista's prudency arguments, the Company addresses the four factors the Commission has considered when determining prudency. For the first factor, Avista reiterates its need for resources by arguing that the investments are necessary to operate Colstrip Units 3 and 4 at a 1480 MW capacity to maintain the plant in a safe and reliable manner while generating its 15 percent share of the plant in accordance with its O&O Agreement.[231] Avista further highlights that the contracts governing its investments in Colstrip: (1) "have never, themselves, been deemed to be imprudent;"[232] and (2) provide for upkeep, ongoing maintenance, preventative work to dispose of coal ash residuals, replacement of plant equipment, and periodic work, which are "based on the original

[228] McGuire, Exh. CRM-1CT at 8:18-9:5.

[229] RCW 19.405.010(2) ("In implementing this chapter, the state must . . . provide safeguards to ensure that the achievement of this policy does not impair the reliability of the electricity system or impose unreasonable costs on utility customers."

[230] *See,* RCW 19.405.010(4)(" The legislature finds that Washington can accomplish the goals of chapter 288, Laws of 2019 while: . . . maintaining safe and reliable electricity to all customers at stable and affordable rates[.]"); RCW 80.28.425(1) (stating in part ""[i]n determining the public interest, the commission may consider such factors including, but not limited to, . . . health and safety concerns . . . to the extent such factors affect the rates, services, or practices of a[n] . . . electrical company.").

[231] Kinney, Exh. SJK-1T at 4:16-20 and 5:3-10 and SJK-2C, O&O Agreement Sections 10 and 17.

[232] Kinney, SJK-1T at 5:17-18.

equipment manufacturer's recommendations [and] adjusted over time by plant personnel based on their operational experience."[233]

135 Avista also notes that historically coal-fired plants have required significant capital maintenance due to "fuel handling, high operating temperatures, emissions controls, and coal ash handling."[234] To support its contention that it has acted reasonably to avoid unnecessary investments, Avista emphasizes its "overall level of capital spending for 2024 and 2025 being at a consistent level with prior years;" and that NWE did not request levels of capital investment beyond the ordinary course of business.[235]

136 For the second factor regarding alternatives considered, Avista argues that as a minority owner of Colstrip, it had no acceptable alternatives. Avista explains that it could not "unilaterally deny the approval of a budget by voting its 15 percent share" to prevent approved capital projects[236] or refuse to pay its 15 percent portion of any approved plant additions as this would result in the Company violating its contractual obligations under its O&O Agreement and expose customers to unreasonable risks of financial penalties.[237] Avista further highlights that the regulatory, financial, and transactional constraints it was facing relating to: (1) federal Mercury and Air Toxic Standard (MATS) compliance obligations;[238] (2) CETA's mandate prohibiting it from serving its Washington retail load with coal-derived electricity after December 31, 2025;[239] (3) limited availability of willing counterparties;[240] and (4) the Company's need to preserve its' contractual and physical rights of the Colstrip Transmission system;[241] collectively compelled it to abandon the plant at no value as this was "the least-cost, least-risk option available" to the Company and its customers.[242]

137 In short, Avista reasons that the transaction "extricated [it] from imminent MATS compliance liabilities, satisfied the statutory coal-elimination mandate, preserved

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233 Kinney, SJK-1T at 6:3, 7:10-11 and 8:4-6.

234 Kinney, SJK-1T at 8:11-13. See also SJK-1T at 8-9.

235 Avista's Post-Hearing Brief at 14:9-10 citing Kinney SJK-1T at 9-10.

236 Kinney, SJK-1T at 7:3-4.

237 Kinney, SJK-1T at 14:4-9 citing to Exh. SJK-2C at 24, Section 21 (e-f) of O&O Agreement.

238 Kinney, SJK-11CT at 4:10-17.

239 Kinney, SJK-11CT at 5:9-10.

240 Kinney, SJK-11CT at 6:5-13.

241 Kinney, SJK-11CT at 6:15-16.

242 Kinney, SJK-11CT at 7:10-11.

valuable transmission entitlements, and avoided the protracted litigation that would have ensued had Avista attempted unilateral retirement outside the consent of its co-owners."[243] Accordingly, Avista concludes that its actions were reasonable given the available information and maintains that any other "hypothetical alternative would have required [it] to retain a non-economic asset, pour capital into environmental controls it could never recover, or surrender transmission benefits needed to ensure adequate energy supply…worth tens of millions of dollar annually."[244]

138 Next, Avista counters AWEC's suggestion that it could have retained its ownership and operated Colstrip as a merchant plant. Specifically, Avista argues that its 15 percent ownership share would make such arrangement untenable because it would prevent the Company from controlling dispatch decisions, and force it "to participate in projects under the requirements of the operating agreement when market prices are relatively low," and demands from the majority of the other owners need it to serve customer loads.[245] Avista also argues that such arrangement would require it to operate as a non-regulated subsidiary and create greater uncertainty with benefits arguably flowing solely to shareholders instead of to customers, and if the plant were fully depreciated, then customers would bear all the costs of the depreciated asset.[246]

139 For the third prudency factor, communication and involvement of the Company's Board of Directors, Avista maintains that its owner representatives actively exercised their ownership interests concerning capital spending by meeting both annually with the Plant Operator, to discuss the Operating and Maintenance, Capital and Asset Retirement Obligations budgets,[247] and every other month to review plant operations and discuss other projects being vetted.[248] Avisa also notes that its Board of Directors and senior leadership were involved in the Company's decision to approve Colstrip Unit 3 and 4 plant additions, and regularly answered questions as they arose, made recommendations, and approved the overall levels of annual capital expenditures and investments.[249]

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[243] Kinney, SJK-11CT at 7:12-15.

[244] Kinney, SJK-11CT at 7:17-20.

[245] Kinney, SJK-11CT at 8:11-16.

[246] Kinney, SJK-11CT at 8:17-22.

[247] Kinney, SJK-1T at 6:10-22 and Exh. SJK-2C at12, Sections 10, 17-21, Section 17 of O&O Agreement.

[248] Kinney, SJT-1T at 16:4-11.

[249] Kinney, SJK-1T at 16:14-23 and 17:1.

140 With respect to the fourth prudency factor of adequate documentation, Avista contends that it maintained relevant contemporaneous documentation related to its decisions on plant additions and operations costs, as well as its cost-benefit analyses provided in the Company's exhibits marked SJK-4C, SJK-5C, and SJK-6C.[250]

141 In response, Staff and NWEC criticize Avista's consideration of project alternatives by arguing that the Company's net present value (NPV) analysis is flawed, because it is not risk adjusted for the probability of a Colstrip shutdown, and incorrectly includes benefits beyond 2025.[251] Staff argues that the NPV analysis included in Avista's Exhibits SJK-4C and SJK-5C were not: (1) calculated in a manner to allow parties to assess whether the benefits to Washington ratepayers outweigh the costs; and (2) risk adjusted and calculated to account for the probability of the existing equipment failing in the near term.[252] By not limiting its consideration to the costs and benefits of investments "incurred or accrued before January 1, 2026, the time after which Avista needed to remove Colstrip from its allocation of electricity," Staff reasons that the Company was guided by an "unreasonably flawed analysis."[253] Namely, Staff asserts the Company: (1) implicitly assumed 100 percent probability of an asset failure resulting in an outage if the investment were not pursued; and (2) artificially increased and overstated the benefits associated with replacing particular investments in plant.[254] Staff further maintains that Avista did not adequately support its assertion that the cost of short term power would exceed the cost of further capital investment because it relied on post-decisional analysis from Kinney's rebuttal testimony, "which did not exist" when Avista initially made these investments.[255] Staff thus concludes that the subsequent calculations Avista performed to risk adjust its NPV analysis should not carry any weight in the Commission's determination of prudence.[256] Finally, despite Staff's arguments of the methodological flaws and failure of Avista to comport its decision making processes with each of the prudency factors, Staff acknowledges that these investments do provide some benefits to

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[250] Kinney, SJK-1T at 17:5-11; Kinney, SJK-11CT at 19:8-9; SJK-4C; SJK-5C; and SJK-6C.

[251] McGuire, CRM-1CT at 17-24 and Cebulko BTC-1CT at 16:3-12.

[252] McGuire, Exh. CRM-1CT at 18:15-21 and 19:1-2. See also Staff's Post Hearing Brief at 6 ¶ 13.

[253] Staff's Post Hearing Brief at 9 ¶ 20.

[254] McGuire, CRM-1CT at 22:1-11.

[255] Staff's Post Hearing Brief at 16-17 ¶¶ 40-42. See also Kinney, TR at 41:16-21 (October 3, 2025).

[256] Staff's Post Hearing Brief at 17 ¶ 41.

ratepayers.[257] Therefore, to reconcile the methodological flaws against the benefits conferred to ratepayers, Staff recommends "prorating recovery based on the number of months each asset will serve Washingtonians (meaning the time between the in-serve date and the end of 2025) divided by the total number of months in the service life of the asset."[258]

142 Like Staff, NWEC argues that there is insufficient information in the record demonstrating that Avista met its burden to demonstrate that its costs were prudently incurred.[259] NWEC argues that Avista's NPV analysis was flawed because the Company limited its analysis to just 12 projects and assumed a single probability of failure rather than differentiating the risk of an outage between each project.[260] By improperly assuming a 100 percent probability of failure in the event that a capital asset was not pursued, NWEC reasons that Avista overstated the benefits of the plant continuing to operate without such investment.[261] NWEC further maintains that Avista failed to present contemporaneous evidence to support a prudence finding for its sixteen investments extending life beyond December 31, 2025,[262] and proposes that the Commission reject Avista's proposal to allow full recovery of such investments. NWEC also argues that Avista failed to demonstrate that it conducted a sufficient analysis of its power cost by: (1) "only focus[ing] on the benefits of investing in Colstrip in a single year as compared to what power costs would have been in that year if Avista relied on market power;" (2) "overestimat[ing] the availability of Colstrip Units 3 and 4, given the increasing frequency with which Colstrip has faced forced outages;" and (3) only considering "fuel costs, not capital investments."[263] Accordingly, NWEC requests that the Commission disregard the informal "risk-adjusted" analysis Avista incorporated in its rebuttal testimony on the basis that it did not provide evidence that it developed its analysis contemporaneously with its decision-making.[264]

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[257] Staff's Post Hearing Brief at 21 ¶ 52 citing to McGuire, Exh. CRM-1CT at 25:6-15.

[258] Staff's Post Hearing Brief at 21-22 ¶ 53 citing to McGuire, Exh. CRM-1CT at 26:13-18.

[259] Cebulko, BTC-1CT at 8:6-9.

[260] NWEC's Post Hearing Brief at 1 ¶ 2.

[261] Cebulko, BTC-1CT at 16:8-10.

[262] NWEC's Post Hearing Brief at 1-2 ¶ 3.

[263] NWEC's Post Hearing Brief at 10 ¶ 24.

[264] NWEC's Post Hearing Brief at 12 ¶ 28.

143 However, unlike Staff and NWEC,[265] AWEC and Public Counsel[266] recommend that the Commission prorate the 2024 and 2025 capital additions based on the number of months each asset will serve Washingtonians prior to December 31, 2025, and only allow recovery of costs that are prudent and used and useful.[267]

144 Avista contends on rebuttal (1) that the parties disregard the value and significant benefits customers have received from the long-lived power plant in the form of lower power supply costs during peak demand and high price events; and (2) that "[a] simple cost benefit analysis has never been the <u>sole</u> determinant of prudence."[268] Despite the concerns Staff and NWEC raise, Avista maintains that it did perform a cost benefit analysis and demonstrated a favorable present value of plant additions in its "hurdles sheets contained in Exhibits 4C-5C," which are "project-by-project risk assessments" that are used to aid the project operator in determining the need and timing for each capital project.[269]

145 Finally, although Avista acknowledges that it did not initially risk adjust its NPV analysis, it argues that the financial risk of having Colstrip out of service on an equipment failure would be more cost prohibitive in nearly all cases than supporting the costs of replacement.[270] To support this contention, Avista explains that when it did perform subsequent calculations to risk adjust its NPV analysis, it applied a 12.6 percent annual forced outage rate from its 2024 general rate case and removed any assumed benefits after 2025 for the 12 disputed capital projects in 2024 and 2025 and ultimately determined that the 12 projects had "a higher risk adjusted <u>outage cost</u> than the investment itself."[271] Thus, Avista concluded that even "a 'risk adjusted' NPV analysis

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[265] Staff's Post Hearing Brief at 21-22 ¶ 53 citing to McGuire, Exh. CRM-1CT at 26:13-18.

[266] Dreyer, Exh. JMD-1CT at 3:11-14 and JMD-2T at 3:6-18 citing to Mullins, Exh. BGM-1T at 11:18-20.

[267] Mullins, Exh. BGM-1CT at 3:11-16 and Public Counsel's Post Hearing Brief at 17 ¶ 53.

[268] Avista's Post Hearing Brief at 13 ¶ 40 citing to Kinney, SJK-11CT at 19:1-5 (emphasis in original).

[269] Avista's Post Hearing Brief at 13 ¶ 41.

[270] Kinney, SJK-11CT at 19:2-3 and 19:17-20. To support its contention Avista provides an example of a cooling tower fill replacement (Project No. 10028050-900). Avista explains that the fill replacement for Unit 4 was estimated at approximately $413,000 for its 15 percent share, and that if such repair were not performed and led to a de-rate or shut-down of the plant, obtaining replacement costs of power could range from as low as $7 million at a 12.6 percent risk of outage and be as high as $22.3 million in a high market time for just a seven day period. Avista's Post-Hearing Brief at 13-14 ¶ 42-44 and SJK-11T at 20:5-20.

[271] Avista's Post-Hearing Brief at 14 ¶44 citing to Kinney, SJK-11CT at 21:1-18 and 22:1-8.

shows that the benefits of keeping the plant fully operational throughout 2024 and 2025 far outweigh the costs" of the capital investments at issue in this proceeding.[272]

SmartBurn Projects

146 In its initial filing, Avista argues that the six SmartBurn projects are needed to allow the boiler system to continue to work to "maintain a functioning and crucial system regarding the combustion and NOx controls" since "the tips of the air ducts are subject to a furnace environment – extreme heat and coal dust abrasion – that causes the tips to distort, and in some cases fail."[273] Avista explains that Smart Burn was commissioned to study different design options to better control NOx emissions, and that the SOFA Bucket Replacement U3 and Boiler Burner AuxAir Replacement U3 systems were installed between 2007 and 2009.

147 The result of these efforts was "the design and supply of new top over fire air (TOFA) air system burners,[274] which was the work related to the SmartBurn investment previously denied by the Commission in Docket UE-200900, et. al,[275] not the work performed on SOFA and the Aux Burners.[276] Accordingly, Avista maintains that the SOFA and Aux Boiler Burners should be recoverable because they "existed prior to installation of the SmartBurn technology and would have continued to operate had the TOFA technology never been installed.[277] However, in rebuttal Avista removes the 2024 and 2025 TOFA Bucket Replacement U3 and U4 investments, which it asserts were included in error in its initial filing.[278] Additionally, Avista notes that although NWEC calls for the disallowance of SOFA, it "mistakenly places costs related to the Control Room Operator (CRO) Simulator Replacement, Project No. 10082239-900, in the same category as

[272] Kinney, Exh. SJK-11CT at 13:18-20.

[273] Kinney, SJK-11CT at 24:9-11. See also Staff-DR-001C Supplemental Confidential Attachment A.

[274] Avista Witness Kinney explains that the Commission specifically disallowed only the TOFA ports installed in 2016 and 2017, not the SOFA Burners and Burner Aux Air System), which was installed in 2007 and 2009, well before 2017 when the SmartBurn TOFA technology was installed. Kinney, SJK-11T at 25:22 and 26:1-4.

[275] Dockets UE-200900 et.al., Final Order 08/05 at 94 ¶¶ 264-265.

[276] Kinney, SJK-11CT at 24:20-23, 25:21-23 and 26:2-4. Avista emphasizes that in that Order, the Commission only disallowed the TOFA ports installed in 2016 and 2017, not the SOFA or Boiler Aux Air System, which were installed in 2007 and 2009, well before the 2017 Smart Burn technology was installed.

[277] Kinney, SJK-11CT at 26:14-16.

[278] Kinney, SJK-11CT at 26:19-21.

SmartBurn."[279] Avista explains this is an error, because the "CRO simulator is not specific to the operation of SmartBurn equipment only," and "would have been installed whether or not Avista had invested in SmartBurn." [280] As such, Avista concludes that it should be allowed.

148 While all non-company parties initially contested Avista's request for recovery of the six discrete SmartBurn projects, following Avista's removal of the 2024 and 2025 TOFA Bucket Replacement U3 and U4 investments, Staff accepted in its post-hearing brief Avista's revised position on rebuttal.[281]

149 However, NWEC continues to recommend that the Commission "fully disallow recovery of the SmartBurn-related investments."[282] Specifically, NWEC argues that although Avista claims that its SOFA and Boiler Burner Aux investments preceded the time period that the TOFA ports were installed, and are meaningfully distinct, that Avista failed to support either contention.[283] NWEC further argues that while these two investments might not have been at issue in Avista's 2020 GRC in Docket UE-200900, et. al., the Commission's reasoning for disallowing SmartBurn in that docket should broadly apply to all SmartBurn related investments "because the Company did not 'address Staff's primary concern that SmartBurn was not required by law.'"[284] As such, NWEC concludes that the Commission should reject Avista's attempt to mischaracterize its prior decision and deem the investments imprudent.[285] Finally, in response to Avista's contention that NWEC witness Cebulko misclassified the CRO Simulator as a SmartBurn project, NWEC "now recommends that Commission classify the CRO Simulator as a life-extending investment" and disallow recovery on the basis that its useful life is longer than 3-4 years and thus should not be classified as major routine maintenance.[286]

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[279] Kinney, SJK-11CT at 17:103 citing Cebulko, BTC-1CT at 31:10-13.

[280] Avista's Post Hearing Brief at 16 ¶ 49, Kinney, SJK-11CT at 27:4-6, and Evidentiary Hearing TR at 96:10-13 (October 3, 2025) quoting Staff Witness McGuire disagreeing with NWEC's assessment ("stating…Staff does not agree with that assessment. The simulator was not part of what the Commission disallowed in its final order in the 2020 Avista general rate case.").

[281] Staff's Post Hearing Brief at 5 ¶ 11.

[282] NWEC's Post Hearing Brief at 14 ¶ 32.

[283] NWEC's Post Hearing Brief at 14 ¶ 33.

[284] NWEC's Post Hearing Brief at 14 ¶ 34 citing Dockets UE-200900 et. al, Final Order 08/05 at 94 ¶ 264.

[285] *Id*.

[286] NWEC's Post Hearing Brief at 15 ¶ 36.

150 While AWEC and Public Counsel's response testimony did not specifically address whether SmartBurn investments, previously disallowed in Avista's 2020 GRC should be recovered, each continue to support disallowance of these costs in this proceeding on the basis that they were previously determined to be imprudent.[287] However, AWEC clarifies in its post hearing brief that while it generally "supports the exclusion of SmartBurn costs previously disallowed," that "[t]o the extent the Commission finds that some or all of the SmartBurn costs have not been previously disallowed, these investments should be prorated."[288]

Commission Determination

151 During general rate case proceedings, the Commission determines the prudence of utility actions by reviewing whether the utility made reasonable business decisions in light of the facts and circumstances known or that reasonably should have been known to the utility at the time decisions were made.[289] What is reasonable requires assessment of choices made, in light of circumstances and possible alternatives, based on industry norms and practices.[290] Prudence does not require a single, ideal decision, but requires the utility to make a reasonable decision among a number of alternatives that the Commission might find prudent.[291] The prudence review "requires evaluation of the Company's decisions not just from the perspective of management for the benefit of shareholders, but also for the benefit of customers."[292] The fundamental question for decision is whether management acted reasonably in the public interest, not merely in the interest of the company.[293]

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[287] AWEC's Post Hearing Brief at 9 ¶ 18, 11 ¶23, and Dreyer, JMD-1CT 5:7-11. See also Dreyer, Exh. JMD-4C (Avista's Response to Staff Data Request No. 1C, Attachments A&B) and JMD-5 (Avista's Response to Staff Data Request No. 7).

[288] AWEC's Post Hearing Brief at 11-12 ¶ 23.

[289] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12 at ¶ 19 (Apr. 7, 2004).

[290] *Id*.

[291] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 & UG-090705 (*consolidated*), Order 11 at 119 ¶ 337 (Apr. 2, 2010).

[292] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 14 at 34-35 ¶ 65 (May 13, 2004).

[293] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 14 at 34-35 ¶ 65 (May 13, 2004) (quoting Goodman, The Process of Ratemaking, at 857).

152 The prudence standard applies to both the question of need and the appropriateness of the expenditure.[294] The Commission considers three broad questions when evaluating prudence: (1) Was the initiation of the project prudent; (2) Was the continued implementation of the project prudent; and (3) Were the expenses prudently incurred?[295] The second and third factors are examined using the same prudence test as the first factor, but applied at a different point in time and necessarily premised on a reevaluation of the project.[296] Consequently, the Commission's prudency review is not limited to a single point in time and encompasses the implementation and construction phases of a project to ensure that a regulated utility continues to reasonably control and evaluate a project.

153 As noted above, when evaluating prudence, the Commission reviews utility decision-making at the time decisions were made. Stated differently, the Commission will not use the benefit of hindsight when evaluating prudence.[297] Consequently, regulated utilities are required to maintain contemporaneous records of their decision-making process and analysis to satisfy the Commission's prudency standard.[298] A utility's "robust discussions" about a project, with a "consensus" on decisions, is not sufficient to demonstrate prudence.[299] Rather, "the parties and Commission should be able to follow the company's decision-making process, knowing what elements the company used, and the manner in which the company valued those elements. Such a process should certainly be documented."[300] "Documentation and evidence of prudence decision making must be kept contemporaneously with a company's decision making or the Commission's ability to evaluate prudence is thwarted."[301]

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[294] *WUTC v. PacifiCorp*, Docket UE-152253, Order 12 at 33 ¶ 94 (Sept. 1, 2016).

[295] Docket UE-152253, Order 12 at 34 ¶ 95.

[296] *Id* at 34 ¶ 95.

[297] *WUTC v. PacifiCorp,* Docket UE-152253, Order 12 at 34 ¶ 94 (Sept. 1, 2016).

[298] *WUTC v. Puget Sound Power & Light Company*, Dockets UE-920433, UE-920499, & 921262, 19th Supp. Order, at 15-16 (Sept. 27, 1994) ("The company's lack of contemporaneous evaluation and documentation is, at best, poor management practice."); *WUTC v. PacifiCorp,* Docket UE-152253, Order 12 at 36 ¶ 102 (Sept. 1, 2016) ("However, this memo was prepared after the final decision to proceed was made, and therefore cannot be shown to have played a part in the Company's decision-making.").

[299] *WUTC v. Puget Sound Power & Light Company*, Dockets UE-920433, UE-920499, & 921262, 19th Supp. Order at 16 (Sept. 27, 1994).

[300] *WUTC v. Puget Sound Power & Light Company*, Dockets UE-920433, UE-920499, & 921262, 19th Supp. Order at 16 (Sept. 27, 1994).

[301] *In re Investigation Regarding Prudency of Outage and Replacement Power Costs*, Docket UE-190882, Order 5 at 12 ¶ 43 (Mar. 20, 2020).

154 The Commission has previously explained that its review of prudence typically focuses on four factors:

> (1) The Need for the Resource: The utility must first determine whether new resources are necessary. Once a need has been identified, the utility must determine how to fill that need in a cost-effective manner. When a utility is considering the purchase of a resource, it must evaluate that resource against the standards of what other purchases are available, and against the standard of what it would cost to build the resource itself.
>
> (2) Evaluation of Alternatives: The utility must analyze the resource alternatives using current information that adjusts for such factors as end effects, capital costs, dispatchability, transmission costs, and whatever other factors need specific analysis at the time of a purchase decision. The acquisition process should be appropriate.
>
> (3) Communication With and Involvement of the Company's Board of Directors: The utility should inform its board of directors about the purchase decision and its costs. The utility should also involve the board in the decision process.[302]
>
> (4) Adequate Documentation: The utility must keep adequate contemporaneous records that will allow the Commission to evaluate the Company's decision-making process. The Commission should be able to follow the utility's decision process; understand the elements that the utility used; and determine the manner in which the utility valued these elements.[303]

1. Prudence of the Prorated Portion of the Four SmartBurn Projects

155 Each of the non-company parties recap in their briefing and testimony the Commission's disallowance of SmartBurn NOx control system investments in Avista's 2020 GRC, in which the Commission found that "Avista failed to demonstrate that SmartBurn was necessary and failed to produce documentation sufficient to demonstrate that its costs were prudently incurred."[304] On rebuttal, Avista removed its two TOFA investments it included in its initial request in this docket in error but maintained its request for the remaining four SmartBurn projects. Avista clarified that the four SmartBurn investments it seeks to recover in this docket were related to components installed in 2007 and 2009

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[302] *WUTC v. Puget Sound Energy*, Dockets UE-111048 and UG-111049 (consolidated), Order 08 at 148 ¶ 409 (May 7, 2012) (citation omitted).

[303] *WUTC v. Puget Sound Energy*, Dockets UE-111048 and UG-111049 (consolidated), Order 08 at 148 ¶ 409 (May 7, 2012) (citation omitted).

[304] Avista 2020 GRC Order at 98 ¶¶ 264-265, 274.

and were not part of its request in its 2020 GRC.[305] Staff revised its position in its post hearing brief and now supports recovery of the four SOFA and Boiler Burner Aux Air Replacement U3 and U4 projects.

156 For Avista's remaining four SmartBurn investments at Colstrip for which it continues to request recovery, we find prudent only the used and useful portion of these investments, which corresponds to the percentage of the useful life that was in service before the CETA deadline of December 31, 2025, and that provided a benefit to Washington customers. As discussed in greater detail in subsection B.2 below, Avista's investments at Colstrip enabled Avista to provide necessary and reliable electric service to Washington customers through the end of 2025. The Company provides evidence showing that the investment decisions were made in communication with its management considering the alternative of replacement power. In addition, the four remaining SmartBurn projects for which Avista seeks recovery are related to components that were operational and found prudent prior to Avista's 2020 GRC and were not subject to the same analysis that disallowed TOFA component investments in Avista's 2020 GRC. Accordingly, we find the used and useful portion of the four investments in this docket related to the SOFA and Boiler Burner Aux Air Replacement U3 and U4 projects to be necessary and prudently incurred.

2. Prudence of the Prorated Portion of the Remaining Capital Projects

157 Consistent with our determination above for the four SmartBurn projects for which Avista seeks recovery on rebuttal, we find prudent the used and useful portion of the Company's Colstrip capital project investments, which corresponds to the percentage of the useful life of the investments in service on or before the CETA deadline of December 31, 2025.

158 The Commission disagrees that investments that extend the life of Colstrip are categorically prohibited under the prudence standard. Both Staff and NWEC cite to the Commission's order in Avista's 2020 GRC to support their argument that investments that extend the life of Colstrip must be excluded from the Company's rates.[306] However, the Commission's consideration of whether the Dry Ash Disposal project was life

[305] Kinney, SJK-11CT at 24:20-23, 25:21-23, 26:2-4, and 26:14-16.

[306] Staff's Post Hearing Brief at 10 ¶ 23; NWEC's Post Hearing Brief at 6 ¶ 15.

extending in Avista's 2020 GRC was a product of Avista's settlement obligations from a prior GRC, not a component of the Commission's general prudence standard.[307]

159 The Commission finds that the Company has sufficiently demonstrated that the used and useful portions of the Company's Colstrip capital project investments are prudent.[308] With regard to the question of need, the record provides a reasonable showing that the used and useful portion of Avista's investments at Colstrip allowed Avista to continue providing necessary and reliable electric service to Washington customers by supporting continued Colstrip operation through the end of 2025.[309]

160 Regarding consideration of alternatives, no party in this case brings forward evidence showing that any other reasonable, let alone more economically beneficial, option was available to Avista, and that it failed to pursue at the time it made the Colstrip investment decisions at issue in this docket. Similarly, no party here argues that the alternative cost of market replacement power, which Avista considered at the time of incurring these investments, would not have surpassed the costs of continuing to support Colstrip operations through the end of 2025.

161 Accordingly, while Staff and NWEC argue at length that Avista performed an imperfect cost benefit analysis, no other reasonable resource option exists in the record for comparison. The prudence standard is one of reasonableness, and here it appears that Avista chose a more reasonable lower cost alternative to provide necessary service to its customers.

162 The Commission rejects the premise that the prudence standard requires a specific form of cost-benefit analysis. While a utility must include a reasonable analysis as part of its demonstration of need and consideration of alternatives, the Commission does not require a particular type of analysis under the general prudence standard, leaving the utility with discretion to develop a cost analysis that is reasonable under the circumstances. The Commission has found previously that, while the Commission will not "preapprove" a

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[307] *WUTC v. Avista Corp.*, Dockets UE-200900, UG-200901, & UE-200894 (*consolidated*), Order 08/05 at 100 ¶ 279 (Sept. 27, 2021) ("Lastly, we are uncertain that Dry Ash is not a life-extending capital addition. Our 2019 Avista GRC Final Order approved a settlement that included an agreement by Avista not to support capital expenditures beyond routine capital maintenance costs that would extend Colstrip's operational life beyond December 31, 2025.").

[308] The Commission declines AWEC's invitation to articulate a prudence standard regarding all investments that extend the life of fossil fuel resources that departs from its longstanding prudence framework. The Commission is not persuaded that a modification of its well-established standard is necessary or warranted.

[309] Staff's Post Hearing Brief at 21 ¶ 52 citing to McGuire, Exh. CRM-1CT at 25:6-15.

particular type of analysis to support prudence, a utility risks a disallowance if it presents an analysis that has insufficient detail or otherwise lacks credibility.[310] Therefore, while cost-benefit analysis may be probative of a company's decision-making process, we reaffirm that a particular form of cost-benefit analysis is not strictly required, nor is it the only thing required, to demonstrate prudence.

163 The Commission further finds that Avista's NPV analysis is sufficiently reasonable even though it is not performed from the perspective of Washington ratepayers. While the Commission will not proscribe the type of analysis that a utility may utilize to support its showing of prudence, if such analysis is based on general rather than Washington-specific data, the utility should be able to explain how that data supports prudence from the perspective of Washington ratepayers. In some cases, there may be no distinction between the general benefit and the Washington specific benefit, insofar as the Washington benefit is a proportional share of the general benefit. But, in circumstances where the Washington benefit may materially diverge from the general benefit, such as when a resource may no longer be used to provide service in Washington, further analysis should be performed to verify that the investment is still prudent with respect to Washington ratepayers.

164 Avista provided contemporaneous documentation showing that in consultation with its board of directors in the budgeting process the Company considered the cost of replacement power in lieu of making the 2024 and 2025 plant investments at Colstrip. In addition, the favorable NPV analysis Avista conducted for the projects constitutes sufficient analysis to support the investment decisions for the portion of projects' use through the end of December 2025. Up to the CETA deadline, the NPV analysis provides a reasonable weighing of costs versus benefits that would accrue to Avista's Washington customers.

165 We agree with Staff that Avista's additional post-decisional analysis does not constitute contemporaneous documentation probative of what the Company considered when making decisions to invest in the capital projects at issue here. Nevertheless, we view the contemporaneous material Avista provided as sufficient to meet the reasonableness standard of prudence for service prior to December 31, 2025. Avista's additional analysis

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[310] *WUTC v. Avista Corp*, Dockets UE-150204 & UG-150205 (*consolidated*), Order 05 at 69 ¶ 193 (Jan. 6, 2016) ("While we do not make a decision regarding the prudence of this project in this proceeding, we note the considerable uncertainty surrounding the business case analysis Avista prepared. . . .We look forward to a more refined cost-benefit analysis in a future proceeding, including a fuller discussion of "non-quantifiable benefits" suggested by Mr. Kopzcynski.").

provides nothing more than a post hoc after-the-fact analysis that would have lent additional support, had the Company performed the analysis at the time of the decision to invest in the Colstrip capital additions.

166 Given the above discussion, the Commission finds that the Company has demonstrated a need for the prorated portions of the Colstrip assets in this case based on the NPV analysis and forecasted replacement power costs. The same evidence also supports a finding that the Company considered alternatives to continuing to fund Colstrip and that it documented its reasoning contemporaneously and demonstrates that Avista informed and consulted its management about the investment decisions related to Colstrip.

167 No party in this docket disputes that replacement power is a more expensive option to provide needed service to customers and would increase the burden and decrease benefits to ratepayers had Avista chosen to abandon the use of Colstrip electricity earlier than necessary under CETA. Thus, we find Avista's decisions to invest in the used and useful portion of its capital expenditures at Colstrip for 2024 and 2025 were reasonable and prudent.

168 As to the equity considerations raised by Public Counsel regarding Avista's request in this docket, the Commission has addressed this issue by prorating Avista's recovery of Colstrip costs.[311] Prorating Avista's recovery of investments in Colstrip promotes equity by appropriately assigning costs to Washington customers relative to the benefits that they will receive before coal-fired resources can no longer be included in Avista's allocation of electricity. The Commission's analysis in this matter is also informed by the numerous public comments filed in this docket raising concerns about affordability and opposing continued support for coal-fired resource operations past 2025 despite CETA's mandate to remove coal from the allocation of electricity.[312]

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[311] *WUTC v. Cascade Natural Gas Corp.*, Docket UG-210755, Order 09 at 19-20 ¶ 59 (Aug. 23, 2022) (retaining discretion to evaluate equity on a case-by-case basis). However, the Commission declines to consider the articles cited by Public Counsel in its briefing, as those articles are not part of the record in this case, and Public Counsel has not motioned for the Commission to take official notice of those articles or explained why they could not have been previously submitted to the record. *See* Public Counsel's Post Hearing Brief at 21-22 ¶ 64-65.

[312] *See generally* Offer of Public Comment, Exh. BR-4, Public Comment Exhibit and UTC Matrix Attachment A at 4-7.

VII. Inventory Balances

169 AWEC recommends disallowing Washington's share of Avista's Colstrip inventory balances of $4.0 million, which result from the Materials and Operating Supply Inventory in the amount of $2.8 million and the Colstrip Fuel Stock Coal Inventory (FERC Account 151.120) in the amount of $1.2 million. AWEC raises concerns about Avista's response to a Staff data request asking why the Company "increased certain inventory costs to just over $4.0 million when the 2024 values were $0." Avista responded that "it moved outstanding fuel stock and inventory balance to Colstrip tracker as a way to allow the Company to recover the balances by the end of the year 2025."[313] AWEC questions that this was the first time Avista identified these balances, and that the amounts were not included in the Company's Colstrip 99 tracker when it was first established.[314]

170 On rebuttal, Avista witness Andrews explains that AWEC is correct "that the Company had not specifically identified these inventory balances when the Colstrip Schedule 99 tracker was first established," and that it did not include these balances in its prior 2023 or 2024 Schedule 99 filings.[315] Andrews clarifies that the Materials and Operating Supply Inventory includes "essential materials and parts needed to keep the Colstrip plant running smoothly," and "covers items known to wear out or fail out during normal operations . . . to prevent forced outages."[316] The Colstrip Fuel Stock Coal Inventory a/k/a 'Dead Storage,' "allows Colstrip to maintain a 28-day reserve of coal fuel to safeguard against long-term supply disruptions from the Westmoreland mine caused by weather, equipment failure, regulations, or labor issues."[317] Andrews maintains that the reason Avista did not initially include these inventory balances was "because these balances were not [a] capitalized plant or a regulatory asset that was incurring depreciation or amortization expense.[318] While it had not been appropriate to include the expenses associated with these balances prior to the current filing, it now seeks to recoup and begin amortizing these balances through December 2025.[319]

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[313] Mullins, Exh. BGM-1CT at 11:6-16 citing to Mullins, Exh. BGM-4, Avista's Response to Staff's Data Request No. 12.

[314] Mullins, Exh. BGM-1CT at 11:6-16.

[315] Andrews, Exh. EMA-1CT at 29:6-9.

[316] Andrews, Exh. EMA-1CT at 29:19-21 and 30:1.

[317] Andrews, Exh. EMA-1CT at 30:8-10.

[318] Andrews, Exh. EMA-1CT at 30:19-21.

[319] Andrews, Exh. EMA-1CT at 31:15-30 and 32:1-17.

171 Accordingly, when Avista began the process of preparing the 2025 Schedule 99 filing and "realized it had failed to remove these inventory balances from Working Capital,[320] currently included in base rates,"[321] to proactively prevent any double recovery, Avista proposes to: [322]

> credit customers within the Colstrip Tariff Schedule 99, effective January 1, 2025, the same return amount on these inventory balances included in base rates of approximately $270,000, so as to result in a $0 impact in 2026."[323]

172 In short, with the completion of Avista's GRC in Docket UE-240006, and approval of an overall rate of return of 7.32 percent, Avista is requesting to create a separate accounting so that "the amount included in error in 2026 [totaling] $393,000," can be "credit[ed] against the 2026 Schedule 99 balances owed to and from customers – resulting in a net $0 customer impact effectively January 1, 2026."[324]

173 Given that Avista "appropriately accounted for the amortization expense in this proceeding, as well as identified the approximate amounts to refund customers in 2026 to return the 'return on' these inventory balances included in base rates in error," AWEC confirms that it is satisfied with Avista's proposed treatment concerning the outstanding Colstrip inventory amounts.[325] No other party raised any concerns or objected to the proposal Avista witness Andrews makes on rebuttal regarding recovery of the inventory balances.

Commission Determination.

174 We find Avista's proposal to account for inventory balances in Colstrip Schedule 99 to avoid double recovery from customers to be appropriate. Avista has properly accounted for the amortization expense and identified the approximate amount customers should be

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[320] Andrews, EMA-1CT at 32:25-29 and 33:1-10 (Avista explains that "the Colstrip Materials and Supplies Inventory (FERC Account 154.400) and Colstrip Fuel Stock Inventory (FERC Account 1541120) balances were inadvertently included in base rates within Washington Electric Working Capital, rather than removed from base rates and alternatively included in Colstrip Tariff Schedule 99 with the effective date of Schedule 99 on December 21, 2023. Furthermore, these inventory balances were included in Washington electric Working Capital in the Company's current general rate case UE-240006 on an AMA basis as of June 30, 2024.").

[321] Andrew, EMA-1CT at 32:18-21.

[322] Andrew, EMA-1CT at 32:18-21.

[323] Andrews, EMA-1CT at 33:5-8.

[324] Andrews, EMA-1CT at 33:10-15.

[325] AWEC's Post Hearing Brief at 13 ¶ 26.

refunded in 2026 for "the return on" the inventory balances, which were inadvertently included in base rates. However, we require Avista to provide the actual adjustment for the 2025 return and to refund the "return on" for 2026 in its compliance filing confirming the removal of the inventory balances (now amortized through Schedule 99) and from working capital in Avista's next GRC filing.

VIII. Process for Refund—True-up and Compliance Filing Requirements

175 Avista proposes a "true-up" for actual Colstrip-related costs "by updating any forecasted balances," from its 2024 and 2025 Colstrip investments, inventory balance and O&M expenses in Schedule 99 from its October 31, 2024 filing, "with the actual costs incurred during the 2025 year."[326] Specifically, after calculating the difference between forecasted and actually approved Colstrip-related costs, Avista proposes that "[i]f the actual costs are lower than revenue recovered through Schedule 99 during 2025 . . . [that] the over-collected amount would be deferred for refund."[327] However, if "the actual costs exceed the forecast, Avista will not seek additional recovery through Schedule 99 . . . as no surcharge for these costs (excluding costs associated with ARO regulatory balances and amortization expenses) are allowed beyond 2025 year-end."[328]

176 While Avista agrees with the non-company parties that any refund to customers should be determined as part of its compliance filing in this proceeding, "anticipated no later than March 31, 2026," Avista proposes "to offset this refund against expected 2026 Colstrip Schedule 99 Tariff balances."[329] Specifically, Avista proposes to submit its Colstrip Schedule 99 filing by October 31, 2025, then after performing a true-up of the final costs, reduce "the 2025 Schedule 99 tariff rate to $0 effective January 1, 2026," then during 2026 offset the actual AROM amortization and other related costs by the 2025 Schedule 99 refunds through December 31, 2026.[330] Further, Avista proposes to defer any over-collected 2025 Schedule 99 revenue or related refunds, as determined by its

[326] Avista's Post Hearing Brief at 25 ¶ 78.

[327] Avista's Post Hearing Brief at 25 ¶¶ 78-79.

[328] *Id* citing to Andrews EMA-1CT at 14:10-16 and Kinney, SJK-1T at 2:23-3:2 (explaining that any "Colstrip related costs Avista will seek to recover in rates after 2025, will be limited to costs associated with decommissioning and remediation that will go before this Commission, pursuant to RCW 19.405.030(1)(b).

[329] Andrews, Exh. EMA-1CT 18:2-6.

[330] Andrews, Exh. EMA-1CT at 18:17-19.

March 31, 2026, compliance filing, "to be submitted on or before October 31, 2026, with an effective date of January 1, 2027."[331]

177 In response, the non-company parties recommend that the Commission order Avista to recalculate its annual 2025 Colstrip Schedule 99 filing in compliance with the Commission's final determinations to ensure that customers are appropriately refunded any amounts to which they are entitled. Additionally, Public Counsel argues that since there "is time value to money," that customers are better served receiving a refund now of "excess utility rates they incurred in 2025 rather than by lower rates at an unspecified future date."[332] Public Counsel further recommends that "the Commission order a refund directly to customers as a bill credit (either a one-time basis or over a period not to exceed one year), rather than allowing the Company to credit that amount against decommissioning and remediation expenses."[333]

Commission Determination:

178 We agree with Public Counsel that "there is time value to money," and with the other non-company parties that customers will be best served by receiving the refund earlier than Avista's proposal to do so in its next Schedule 99 submittal date of October 31, 2026, effective January 1, 2027. We recognize that customers across the state, and especially those who are members of historically impacted communities and vulnerable populations, including those in Avista's service territory, are experiencing significant issues with affordability. The Commission therefore finds a timely refund is appropriate to reduce customer bills. We also understand the Company's concerns associated with cash stability in providing service to customers.

179 Accordingly, we order Avista to issue the refund due to customers in either of the following two options:

(1) as a one-time lump sum credit; or
(2) spread over a period not to exceed three (3) months with carrying costs accruing at the Company's actual, after-tax cost of debt.

180 The Commission finds it reasonable to accept Avista's proposal to submit its compliance filing on or before March 31, 2026. Avista shall submit the true-up and refund in its

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[331] Avista's Post Hearing Brief at 25 ¶¶ 78-82.

[332] Public Counsel's Post Hearing Brief at 24 ¶ 73.

[333] Public Counsel's Post Hearing Brief at 24 ¶ 74 and 25 ¶ 75.

compliance filing by March 31, 2026, as directed in this Order, and expects all Colstrip costs to be removed from Avista's Washington customer rates by the end of 2025 consistent with CETA and Avista's Colstrip Tracker Schedule 99 tariff.[334]

FINDINGS OF FACT

181 Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the parties and the reasons therefore, the Commission now makes and enters the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

182 (1) The Commission is an agency of the state of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including electrical companies.

183 (2) Avista is a "public service company" and "electrical company" as those terms are defined in RCW 80.04.010 and used in Title 80 RCW and is subject to Commission jurisdiction.

184 (3) On October 31, 2024, Avista filed testimony, exhibits, and supporting documentation and proposed revisions to its rates under the Company's electric service tariff, Tariff WN U-28, Schedule 99 Colstrip Tracker.

185 (4) Avista requested an annual increase of $18.2 million, or 2.7 percent, from $23.9 million in 2024 to $42.6 million, and the Company seeks to recover that balance from customers effective January 1, 2025, over the 2025 calendar year.[335]

186 (5) On December 19, 2024, this matter came before the Commission at the Open Meeting and the Commission voted to suspend the filing.

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[334] Avista's request for revision of its Tariff WN U-28, Colstrip Tracker Schedule 99, in Docket UE-250856 is pending as of the date of this Order.

[335] Docket UE-240891, Direct Testimony of Scott J. Kinney Representing Avista Corporation, SJK-1T at 2:8-16. See also Kinney, Exh.SKJ-9C (confidential native workpapers) and SJK-10 (for non-confidential workpapers. The difference between the 2024 Tariff 99 balance for revenue requirement (AMA basis) versus the 2025 Tariff 99 balance (AMA basis) is an increase of $18.7 million. However, when the total revenue requirement runs through the rate design workpapers based on load and allocation factors, the required change in revenue is $18.2 million as provided in witness Kinney's testimony referenced above.

187 (6) On December 20, 2024, Avista filed revised tariff sheets, and the Commission issued Corrected Order 01, Complaint and Order Allowing Rates Subject to Later Review and Refund; Setting Matter for Adjudication in this docket, requiring Avista to file revised tariff pages no later than December 31, 2024, with an effective date of January 1, 2025, indicating that the increased rates are subject to refund.

188 (7) On October 3, 2025, the Commission held an evidentiary hearing before the Commissioners presided over by ALJ's Amy Bonfrisco and Ann Paisner.

189 (8) Colstrip Units 3 and 4 are coal-fired generating units.

190 (9) At 12:00 a.m. on January 1, 2026, Pacific Standard Time, Avista's ownership interest will transfer to NWE and costs associated with coal-fired generation of electricity will be removed from rates for electricity for Avista's Washington customers.

191 (10) As of January 1, 2026, Colstrip will provide no benefit to Washington electric retail customers.

192 (11) As of January 1, 2026, Colstrip will not be necessary or useful in Avista's provision of electric service to Washington customers.

193 (12) Thirteen Colstrip projects related to human health and safety provide near-term, immediate benefits that shall be included in rates.

194 (13) Avista has not demonstrated that its remaining investments in Colstrip, other than the thirteen human health and safety projects previously identified, provide any benefits to Washington customers after December 31, 2025.

195 (14) The record developed in this proceeding does not indicate when the U4 Generator Exciter and the North Cheyenne AAQ System were placed into service.

196 (15) The Commission accepts Avista's removal from its request in this docket of the TOFA Bucket Replacement U3 and U4 System Burner components.

197 (16) The Boiler Aux Burner Air System, Control Room Operator (CRO) Simulator

Replacement, and Separate Over Fire Air (SOFA) Bucket Replacement Systems U3 and U4 are not SmartBurn components that were previously disallowed in Avista's 2019 GRC Settlement, Final Order 08/05 in Dockets UE-200900 et. al.

198 (17) The record demonstrates a reasonable need for the investments in Colstrip Units 3 and 4, other than the SmartBurn TOFA components that Avista removed from its request on rebuttal. The CRO Simulator Replacement and SOFA Bucket Replacement and Boiler Burner Aux Air UE and U4 Systems may therefore be prorated up to December 31, 2025, after which the assets cannot provide any benefit to Washington customers.

199 (18) For the remaining Colstrip investments and costs, Avista has provided sufficient evidence demonstrating that it considered alternatives to its Colstrip investments and costs, consulted with its management, and contemporaneously documented its analysis.

200 (19) Avista shall issue any refund due to customers in either: (1) a one-time lump sum credit; or (2) spread the refund over a period not to exceed three months with carrying costs accruing at the Company's actual, after-tax cost of debt. Based on the analysis in this proceeding, Avista has over-collected $5.86 million. The Commission's calculation of this amount is included in Appendix A (Confidential). [336]

201 (20) Avista shall refund the return on inventory balances inadvertently included in base rates and remove the inventory balances from working capital in Avista's next GRC filing.

202 (21) Avista shall recalculate its annual 2025 Schedule 99 filing in compliance with the Commission's final determinations to ensure customers are appropriately refunded for any amounts Avista over-collected.

203 (22) The Commission finds it reasonable to accept Avista's proposal to submit its compliance filing with the true-up and customer refund consistent with the direction in this Order on or before March 31, 2026.

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[336] Appendix A (Confidential) shall be provided to Avista and parties that have signed the protective order agreement and shall be posted to the docket.

CONCLUSIONS OF LAW

204 Having discussed above all matters material to this decision, and having stated the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

205 (1) The Commission has jurisdiction over the subject matter of, and Parties to, this proceeding.

206 (2) Avista is an electric company and a public service company subject to Commission jurisdiction.

207 (3) Avista bears the burden to demonstrate that its provisional rates subject to refund are fair, just, reasonable, and sufficient. The Commission's determination of whether the Company has carried its burden is determined based on the full evidentiary record.

208 (4) Avista has not demonstrated that the rates allowed to go into effect January 1, 2025, subject to refund, are fair, just, reasonable, and sufficient.

209 (5) Colstrip Units 3 and 4 are coal-fired resources as that term is defined in RCW 19.405.020(7)(a).

210 (6) After a careful analysis considering the canons of statutory interpretation, we interpret the terms "retired" and "retirement" in RCW 19.405.030(3) in accordance with Section II above.

211 (7) The provisions of CETA apply to the proceedings in this docket because we find that the Company will have retired Colstrip Units 3 and 4 pursuant to RCW 19.405.030(3) by 12:00 a.m. January 1, 2026.

212 (8) The A&A Agreement between Avista and NWE is not subject to Commission approval under RCW 80.12.020 because, pursuant to RCW 19.405.030(1)(a)'s requirement that coal-fired resources be removed from Avista's allocation of electricity on or before December 31, 2025, Colstrip Units 3 and 4 will not be able to provide any benefit to Avista's Washington customers.

213 (9) The Commission should reject the request to have Avista file the A&A Agreement for Commission approval pursuant to RCW 80.12.020.

214 (10) The Commission should require Avista, as a condition of this order, to comply with the condition for review of future agreements transferring assets for the purpose of complying with a requirement of CETA, as described in paragraph 67.

215 (11) The 13 human health and safety investments in Colstrip are fully used and useful.

216 (12) Avista has not demonstrated that its remaining capital investments in Colstrip are used and useful for service in Washington after December 31, 2025.

217 (13) The Commission should disallow a prorated portion of the Colstrip capital investments based on the portion of the investment's useful lives in service prior to December 31, 2025.

218 (14) Avista shall file an update to this docket detailing when the U4 Generator Exciter and the Northern Cheyenne AAQ System were placed into service along with all supporting documentation. If either asset was placed into service prior to December 31, 2025, Avista should be allowed to recover a prorated portion of the costs associated with those investments, consistent with the proration methodology described in paragraphs 129-130.

219 (15) The TOFA Bucket Replacement U3 and U4 System Burner components of the NOx control system was previously disallowed in Avista's 2019 GRC Settlement, Final Order 08/05 in Dockets UE-200900 et. al, and are imprudent.

220 (16) Avista's remaining investments and costs related to Colstrip that are not disallowed as not used and useful are prudent.

221 (17) Avista should be required to refund over-collected revenue in accordance with our determination in Section VIII of this Order. The computation of the over-collected amounts are attached to this Order as Appendix A (Confidential).[337]

222 (18) Avista shall file its final regulatory accounting for all Colstrip costs, including true-up and refund consistent with the direction in this Order, as of December 31, 2025, on or before March 31, 2026, and other interested parties shall have the opportunity to review and respond to such filing.

223 (19) This Order fully and fairly resolves the issues in these dockets and is in the public

[337] Appendix A (Confidential) shall be provided to Avista and parties that have signed the protective order agreement and shall be posted to the docket.

interest.

224 (20) The Commission Secretary should be authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order.

225 (21) The Commission should retain jurisdiction over the subject matters and the parties to this proceeding to effectuate the terms of this Order.

ORDER

THE COMMISSION ORDERS:

226 (1) The proposed tariff reviews Avista Corporation d/b/a Avista Utilities filed on October 31, 2024, and suspended by prior Commission Order, are deemed approved, subject to the condition set forth in paragraph 67 of this order.

227 (2) Avista is authorized and required to make compliance filings in this docket including all tariff sheets that are necessary and sufficient to effectuate the terms of this Order. Avista shall file its final regulatory accounting, including true-up and refund consistent with the direction in this Order, for all Colstrip costs as of December 31, 2025, on or before March 31, 2026.

228 (3) Avista is required to comply with the condition for review of future agreements transferring assets for the purpose of complying with a requirement of CETA, as described in paragraph 67.

229 (4) As a condition of compliance with this order, Avista is required to submit an update to this docket indicating when the U4 Generator Exciter and the Northern Cheyenne AAQ System, with supporting documentation, and the record should be reopened for the limited purpose of incorporating this information. If the assets were placed into service prior to December 31, 2025, Avista is authorized to recover a prorated portion of the value of those assets, consistent with the methodology described in paragraphs 129-130.

230 (5) Avista is required to refund over-collected revenue in accordance with our determination in Section VIII of this Order.

231 (6) Avista is required to file its final regulatory account for all Colstrip costs as of

December 31, 2025, as part of its Schedule 99 annual filing on or before October 31, 2026, consistent with the guidance in this Order. As part of such filing, other interested parties shall have the ability to review and contest Avista's investments.

232 (7) The Commission Secretary is authorized to accept by letter, with copies to all Parties to this proceeding, filings that comply with the requirements of this Order.

233 (8) The Commission retains jurisdiction to effectuate the terms of this Order.

Dated at Lacey, Washington, and effective December 19, 2025.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

BRIAN J. RYBARIK, Chair

ANN E. RENDAHL, Commissioner

MILTON H. DOUMIT, Commissioner

NOTICE TO PARTIES: This is a final order of the Commission. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 or RCW 81.04.200 and WAC 480-07-870.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-26-18

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

Exhibit 2-69:
Power Council Overview

Northwest **Power** and
Conservation Council

Established to inform and advance a regional vision for power and fish and wildlife in the Columbia Basin

REGIONAL POWER PLAN

The Council develops a 20-year Power Plan, revised every five years, that ensures the Northwest has an adequate, efficient, economical, and reliable power supply.

Key components of the plan include:

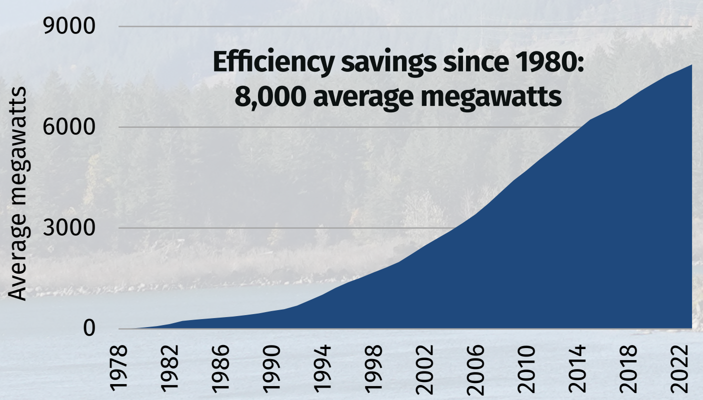
- Electricity demand forecast
- Electricity and fuel price forecasts
- Assessment of cost-effective energy efficiency and demand response
- Least-cost generating resources portfolio
- Ensuring the resource strategy meets the Council's adequacy metrics and thresholds (these standards protect the Northwest power supply's adequacy at peak demand periods)

Bonneville Power Administration funds the Council's work and must act consistently with the Council's plan when acquiring resources. The Council's power planning under the Northwest Power Act emphasizes cost-effectiveness and flexibility, mitigating risk in electric power investments, and ensuring the system's reliability and adequacy. The Power Plan offers regional insights to utilities and regulators.

The Council is in the process of developing its Ninth Power Plan, with a goal of releasing a draft to the public by mid-2026 and adopting it by the end of that year. Challenges include significant regional load growth and a shifting resource mix. Growth in demand for electricity is being driven by data centers, electric vehicles, regional population and economic growth, electrification of buildings, and other sectors.

COST-EFFECTIVE ENERGY EFFICIENCY

Energy efficiency plays a key role in reducing electricity consumption and making loads more flexible and easier to manage in the Northwest. Over the past several decades, energy efficiency has been a go-to way to meet demand at costs much lower than building new plants. This has been an ideal fit with the low-cost, reliable hydropower generated by the Columbia River. Over the past 20 years, power supply shortages have been rare in the Northwest – even as extreme weather events have increased – while regional power costs remain among the lowest in the U.S.



Thanks to effective implementation of the Council's past power plans, the Northwest is a national leader in acquiring cost-effective energy efficiency.

Since 1980:

- The region has met more than half its load growth with energy efficiency
- Almost 8,000 average megawatts has been saved, enough power for more than seven Seattles or the average annual output of three Grand Coulee dams
- $5 billion saved in lower bills for energy consumers and avoided energy costs

COLUMBIA RIVER BASIN FISH AND WILDLIFE PROGRAM

The vision: A Columbia River ecosystem that sustains an abundant, productive, and diverse community of fish and wildlife.

The Council's Columbia River Basin Fish and Wildlife Program represents a 40-year effort to protect, mitigate and enhance salmon and other fish and wildlife in the basin affected by the hydropower system. It is one of the largest mitigation efforts in the world. The Council has tracked important progress on goals and objectives, but significant work still remains.

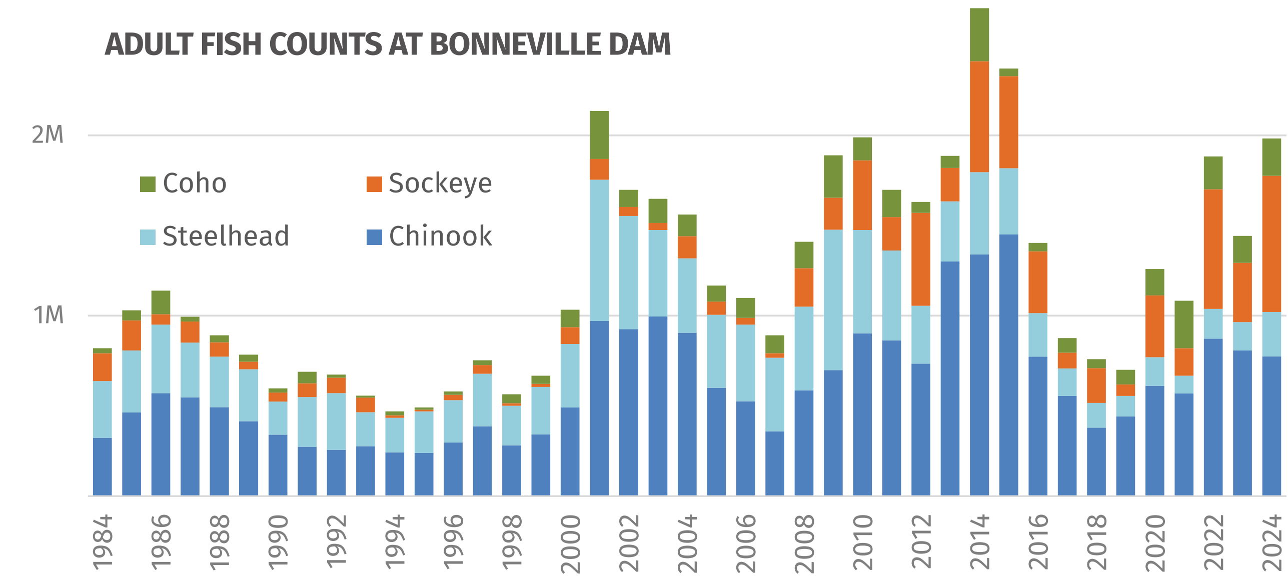
The Program incorporates a variety of strategies, including recommendations for dam operations that improve conditions for fish passage and survival, habitat mitigation, and hatcheries. Target species include salmon, steelhead, and resident fish such as sturgeon and bull trout.

The Council updates the Program every five years based on recommendations from state and federal agencies, tribes, and others. Relevant projects are reviewed by an independent scientific panel.

To date, the Program has:

- Improved water management, flow, and passage to protect and increase survival at Columbia and Snake River dams
- Protected more than 300,000 acres of habitat through purchase or conservation easement*
- Improved over 760,000 acres of habitat through restoration actions**
- Protected 44,000 miles of undammed Northwest rivers and streams

* 1992-2022 ** 2005-2021



In 1980, Congress passed the Northwest Power Act, authorizing the states of Idaho, Montana, Oregon, and Washington to form the Northwest Power and Conservation Council, an interstate compact agency, giving the region a greater voice in how we plan our energy future in the Pacific Northwest and manage natural resources in the Columbia River Basin.

The Act requires the Council to develop, with broad public participation, a regional power plan and a fish and wildlife program.

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updated July 2025

Idaho Council members:

Jeffery Allen
Ed Schriever

Montana Council members:

Douglas Grob
Mike Milburn, Chair

Oregon Council members:

Margaret Hoffmann
Charles F. Sams, III

Washington Council members:

KC Golden
Thomas (Les) Purce, Vice Chair

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-26-18

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

Exhibit 2-70:
Power Council 2021 Power Plan

THE 2021 NORTHWEST POWER PLAN

Northwest **Power** and **Conservation** Council

Contents

document 2022-3 / March 10, 2022

Section 1: Introduction

Electricity generating resources in the Northwest – carbon-free hydropower and nuclear, gas, coal, wind, and solar – plus energy efficiency – have served the region's electricity needs well, providing capacity and energy supporting a reliable, adequate, efficient, and economical power system. In the years since the Council last revised the power plan, however, the power system has experienced changes that place more emphasis on renewables, such as wind and solar generation.

In this 2021 Power Plan, the Council recognizes those states that have requirements and policies pursuing emission reductions that support cleaner electricity generation. Influenced by these policies, this plan includes significantly more renewable generation than all our previous power plans. The Power Act requires that the Council review the plan at least every five years. For this reason, the Council's work focuses most intently on the period between its release and the next one – the time we call the action plan period. However, the plan's forecast through 2041 indicates the region can expect a more substantial transformation in the fleet of regional resources used to generate electricity. Through this transformation into the future, hydropower and energy efficiency will continue to be a fundamental part of the region's power system.

The plan recognizes that there are social, political, and economic drivers leading to the region's turn toward cleaner sources of generation, primarily wind and solar. These intermittent or variable technologies are becoming less expensive to build and are seen as the primary path to reducing emissions associated with generating electricity. This emerging paradigm shift in how the region produces electricity is addressed in the plan's resource strategy. To forecast the potential impacts of this shift, the plan reflects the results of several energy models, public policy, technology, a blend of climate change assumptions, and economics in preparing for the action-plan period and for the longer 20-year plan.

This paradigm shift's attendant risks and the critical importance of reliability raises reasonable questions about the amount of future development of the low-cost renewable resources called for by the plan and the availability of transmission capacity needed to move these resources to load centers. There is also uncertainty regarding whether Western market resources identified by the plan will be available to the region when needed to reduce costs or meet demand, in particular those periods when reliability is at greater risk. Electrification-focused policies in certain states could potentially increase utility loads rapidly, requiring building resources beyond the recommendations laid out in the plan. The plan's recommendations balance a range of uncertainty described both by the underlying analytical work and the wide-ranging expert assessment considered by the Council. These uncertainties that expose anxiety over meeting regional demand with a rapidly evolving electric system have been addressed by the plan using the best information available to the Council and its advisory committees. As the future unfolds, the Council recognizes that new information could prompt reconsideration of the recommendations and that the Council's work to monitor and evaluate the region's evolving system and policies must keep pace and not be tied to traditional timelines.

The Council's work has focused on developing a resource strategy during a time when the region is undergoing significant changes and uncertain futures. This strategy will assure the region an efficient, adequate, economical, and reliable power supply that is available, sufficiently dispatchable, and deliverable within the region's transmission system, where electricity is produced to where it is needed. The Council's work also indicates that as more intermittent or variable generation from wind and solar power is added to the system, a corresponding increase in reserves is necessary. These reserves are accommodated by our existing hydropower, gas, nuclear, and remaining coal generation. In the end, the region's resources must be instantaneously balanced with the region's demand to reliably provide electricity across the entire Northwest power system.

The 2021 Power Plan contains 12 sections that provide more detail and specifics on its components. Section 6 details new and existing resources anticipated to meet future demand for electricity. Our work indicates that the region's large amount of hydropower, nuclear, and traditional thermal resources, including those that burn natural gas and coal, remain an essential part of providing reliable electricity for the region. We also expect that continued acquisition of energy efficiency now and in the future will play a critical role in meeting the region's future demand for electricity. As the Western electricity market changes in such fundamental ways, one thing remains true and certain: Energy efficiency is a very important and fundamental way to address resource adequacy, and its contribution to capacity makes it an important resource during periods of uncertainty. In addition, the future system will be supported by the ongoing development of new renewable resources that are anticipated to provide needed energy while reducing greenhouse gas emissions. We also recognize new demand response opportunities that can be expected to support and reduce system capacity needs. Finally, trading electricity with our neighboring regions in energy markets will continue to support current and future reliability.

The plan is intended to help transition the region into a new paradigm of cleaner energy that includes the use of our abundant hydropower, existing gas, nuclear, and remaining coal generation to provide reliability during the action plan period, while also integrating current and expected future renewables into the power system. As we look to the future, we anticipate that the transition to a new paradigm will be accompanied by risk and uncertainty. The region has dealt with and overcome risk and uncertainty in the past, and it can be expected to do so in the future. Through ranges in values (e.g., natural gas price forecasts, hydro conditions) and in scenario analyses, the plan embraces and addresses uncertainty and risk and provides a strategy for a low-cost, reliable, and adequate system to meet the electricity needs of this time. Implementing the strategy in this plan will require the same flexibility and collaboration used in the past to address the challenges of a new era, while maintaining the reliability expected by Northwest electricity customers.

The Council's work to monitor and evaluate the region's evolving system and policies will keep pace with new data and analysis in this rapidly changing industry. Any changes or unexpected developments will be reported as available, and reflected in the 2021 Power Plan's mid-term assessment.

Section 2: Power Act Requirements and the Power Plan

In December 1980, in direct response to a set of linked problems the region faced concerning increasingly difficult resource issues and the decline of Columbia River salmon and steelhead runs, Congress enacted a comprehensive and innovative legislative solution–the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). The Northwest Power Act was enacted 1) to encourage conservation and efficiency in the use of electric power and the development of renewable resources within the Pacific Northwest; 2) to assure the Pacific Northwest an adequate, efficient, economical, and reliable power supply; 3) to provide for the participation and consultation of states, local governments, consumers, customers, users of the Columbia River system, federal and state fish and wildlife agencies, Indian tribes, and the public at large in the development of regional plans and programs, facilitating orderly planning of the region's power system, and providing environmental quality; and, 4) to protect, mitigate, and enhance the fish and wildlife of the Columbia River and its tributaries, including related spawning grounds and habitat.

The Act was groundbreaking in its use of the Federal Columbia River Power system to achieve cost-effective conservation, its prioritization of conservation and renewable resources, its fish and wildlife protection and mitigation obligations, as well as its required considerations of environmental quality, and, ultimately, its regional power planning process. Remarkably, the Act also implicitly recognized the inherent uncertainty in planning for a future electric power system, with its power planning provisions and planning process providing a venue to accept and manage that uncertainty.

To carry out the Act's purposes, the Northwest Power Act authorized the states of Washington, Oregon, Idaho, and Montana to form an interstate compact agency–the Council–and directed the Council to: 1) prepare and review a "regional conservation and electric power plan" not less than once every five years; 2) prior to each plan, prepare and periodically amend a program to protect, mitigate, and enhance fish and wildlife affected by the Columbia River Basin hydropower system; and 3) develop both the power plan and the fish and wildlife program in a highly public process with broad consultation and participation.

Beyond charging the Council with these specific responsibilities, the Act also specifies, in Sections 4(d) through 4(g) of the Act, the process the Council is to follow in developing and amending the plan; what the Council must include in the power plan; what the Council must do prior to the review of the power plan (undergo a separate process to develop or amend the fish and wildlife program addressed in Section 4(h)); and finally, in Sections 4(d)(2) and Section 6(a) through 6(c), how the Bonneville Power Administration is to use the power plan in implementing conservation measures and acquiring new generating resources.

Public Engagement and Process for Developing the Power Plan

While the Council is directed to prepare a regional conservation and electric power plan, a corresponding directive to the Council, and principal purpose of the Act, is to provide for broad public participation and consultation in the development of that power plan; Sections 4(d)(1) and 4(g) describe how the Council is to implement this mandate and engage the public throughout development and review of the power plan.

Per section 4(g)(3), in the preparation, adoption, and implementation of the power plan, the Council and the Bonneville Power Administration administrator (Bonneville), must encourage the cooperation, participation, and assistance of appropriate federal agencies, state entities, political subdivisions, and Indian tribes. And, Sections 4(g)(1) and (2) add that the Council and Bonneville, in forming regional power policies, must maintain comprehensive programs to inform the public of major regional power issues, obtain public views concerning major regional power issues, and secure advice and consultation from Bonneville's customers and others. Further, the Council and Bonneville must consult with Bonneville's customers, include the comments of such customers in the record of the Council's proceedings for the power plan and fish and wildlife program, and recognize and not abridge the authorities of state and local governments, electric utility systems, and other non-federal entities responsible for the planning, conservation, supply, distribution, and operation of the electric generating facilities.

In practice, these provisions result in a multi-year, highly public process to develop the Council's regional conservation and electric power plan. For the 2021 Power Plan, the Council officially began the power planning process in February 2019 with a webinar that was open to the public and provided information regarding the history of the Act, the planning process, and opportunities for public participation, including through the Council's advisory committees, groups of technical and policy experts from around the region. Early and throughout the process, the Council utilized these advisory committees to gather information on priority issues for the region; conduct analytical work for the power plan; and discuss and review the findings for the power plan.

All advisory committee meetings, and their materials, are open to the public, with broad public notice provided through the Council's website and email distribution lists. The Council discussed substantive issues in its power committee and at regularly scheduled full Council meetings. All meetings are open to the public, again with broad public notice provided through the Council's website and via email distribution, with opportunities for public comment during full Council meetings. In addition, the Council welcomed comment and informal participation and collaboration throughout the planning process through one-on-one meetings with staff and written communications. The comments provided through these opportunities were closely considered by the Council and informed the development of the power plan.

Once the draft power plan is issued, Section 4(d)(1) of the Act requires that the Council hold public hearings on the draft power plan in each of the Northwest states. In addition to the public hearings required under the Power Act, the Council also largely follows the notice and comment procedures of the federal Administrative Procedures Act. Therefore, the Council also provides wide public notice of the draft power plan and ample opportunity to submit written comments, as well as opportunities to provide comment at regularly scheduled monthly Council meetings and testimony at the public hearings. Further, the Council uses this public comment period to conduct consultations with Bonneville, Bonneville's customers, Indian tribes, state and federal agencies, and non-governmental entities to solicit their advice and comment as contemplated under Section 4(g).

Lastly, as a component of the final power plan, the Council explains and describes how comments were considered and responded to during the development of the power plan, including any changes from draft to final. While the process presents unique challenges, broad public participation, engagement, and consultation remain constant in the development of each plan.

Substantive Considerations and Elements in the Power Plan

Section 4(d)(1) provides the basic directive to the Council–to prepare, adopt, and transmit to Bonneville a regional conservation and electric power plan. However, Sections 4(e) and 4(f) provide the substantive priorities, considerations, and elements that the power plan must contain. Section 4(e)(1) specifies that the power plan is to give priority to resources that the Council determines to be cost-effective, with priority given first to conservation; second, to renewable resources; third, to generating resources utilizing waste heat or generating resources of high fuel conversion efficiency, and fourth to all other resources.[1] Given this set of priorities, Section 4(e)(2) then focuses on what the Council is to deliver in its power plan, and that is a "scheme for implementing conservation measures and developing resources…to reduce or meet the Administrator's [Bonneville's] obligations." Further, Section 4(e)(2) requires that the Council must develop this resource scheme (or resource strategy) "with due consideration for (A) environmental quality, (B) compatibility with the existing regional power system, (C) protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish, and (D) other criteria which may be set forth in the plan." Therefore, taken together, these provisions require that the Council develop a cost-effective resource strategy to reduce or meet Bonneville's obligations, and, in doing so bring each of these considerations to bear.

Section 4(e)(3) lists the following specific elements the Council is to include in the power plan, but leaves it to the Council to describe the elements "in such detail as the Council determines to be appropriate":

A. An energy conservation program, including model conservation standards

B. Recommendations for research and development

C. A methodology for determining quantifiable environmental costs and benefits under Section 3(4) of this Act [definition for cost-effective]

D. A demand forecast of at least 20 years, to be developed in consultation with Bonneville, customers, states (including state agencies with ratemaking authority over electric utilities), and the public,

1 Cost-effective is defined in the Act in Section 3(4)(A), and a resource is cost-effective if it has an "estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource, or any combination thereof." Therefore, cost-effectiveness is a comparative exercise of resources.

in such a manner the Council deems appropriate, and a forecast of power resources estimated by the Council to be required to meet the administrator's obligations and the portion of such obligations the Council determines can be met by resources in each of the priority categories. The forecast of power system resources shall also include (i) regional reliability and reserve requirements, (ii) the effect, if any, of the requirements of the Council's fish and wildlife program on the availability of resources to Bonneville, and (iii) the approximate amounts of power the Council recommends should be acquired by Bonneville; this may include, to the extent practicable, an estimate of the types of resources from which such power should be acquired

E. An analysis of electricity reserve and reliability requirements and cost-effective methods of providing reserves designed to insure adequate electric power at the lowest probable cost

F. The fish and wildlife program promulgated prior to the power plan by the Council under Section(h) of the Act

G. Any surcharge recommendation relevant to implementation of the model conservation standards and a methodology for calculating the surcharge

Lastly, Section 4(f) provides and details the model conservation standards to be adopted into the plan and the associated surcharge authority, both addressed as elements of the plan in Section 4(e)(3). While the Act prescribes the elements, it also provides the Council with a substantial amount of discretion to use its expertise to develop and craft these elements for each plan.

For this power plan, the Council decided to structure the plan in such a way that each plan section corresponds with an element identified under the Act. For example, Section 5 details the energy conservation program and Section 9 details the cost-effective methods of providing reserves, while Section 6, Resource Development Plan, comprehensively describes the resource strategy for the 2021 Power Plan. However, specific components from the energy conservation program are also included in the resource strategy discussion of Section 6, as well as analysis and findings from the cost-effective methods of providing reserves detailed in Section 9, which illustrates the way each of these elements work together to inform the Council's power plan.

Relationship of the Power Plan to the Region and Bonneville

As noted above, per Section 4(d)(1), the Council is to prepare, adopt, and transmit to Bonneville a regional conservation and electric power plan, and, per Section 4(e)(2), the Council's power plan is to set forth a "scheme for implementing conservation measures and developing resources… to reduce or meet the Administrator's obligations." Therefore, under the Act, the Council's power plan must consider the entire region while planning for Bonneville's resource obligations. This is because when adopting the Northwest Power Act, Congress envisioned that Bonneville, the federal power marketing agency selling the electrical power produced by the Federal Columbia River Power System, would be the major engine for adding new resources as needed for the region and the purposes of the Act would be achieved through the use of the federal system. Thus, Sections 6(a)(2)(A) and (B) of the Act authorize and obligate Bonneville to acquire sufficient resources to (A) meet the agency's contractual power sales obligations and (B) to assist the agency in meeting the requirements of Section 4(h) of the Act, which is the Council's fish and wildlife program. Moreover, Section 4(d)(2) and Sections 6(a), 6(b), and 6(c) tie Bonneville's implementation of conservation and acquisition of new resources directly to the Council's power plan by requiring that Bonneville's resource acquisitions and conservation implementation be consistent with the Council's power plan, with certain narrow exceptions.

Accordingly, the Act requires the Council to include in the power plan a number of elements concerning Bonneville's resource acquisitions, specifically: A resource strategy to reduce or meet Bonneville's obligations (Section 4(e)(2)); an energy conservation program to be implemented under the Act (Section 4(e)(3)(A)); and a forecast of power resources estimated by the Council to be required to meet Bonneville's obligations and the portion of such obligations the Council determines can be met by resources in each priority category.

The forecast is required to include the approximate amounts of power the Council recommends Bonneville acquire on a long-term basis and may include, to the extent practicable, an estimate of the types of resources (Section 4(e)(3)(D)). For the 2021 Power Plan, to more explicitly recognize this relationship between the Council's power plan and Bonneville, the Council included specific plan sections for Bonneville (See Section 7: Forecast of Federal Power Resources and Obligation to Provide Electricity and Section 8: Recommendation for Amount of Power and Resources Bonneville Power Should Acquire to Meet or Reduce the Administrator's Obligation).

Even though the only legal link provided in the Northwest Power Act to the Council's power plan is to Bonneville and its resource acquisition decisions and conservation implementation, because Bonneville is the primary provider and marketer of electric power in the region, the Council's power plan necessarily affects those entities that purchase power from Bonneville. In addition, the State of Washington's Energy Independence Act tied Washington utilities' conservation potential directly to the Council's methodology for conservation. The Council's power plan is also an influential resource for other entities making resource decisions, as well as for legislators, regulators, and state energy offices around the region. The power plan remains a proper venue for examining the potential implications of policy decisions on the regional system, and how to plan and manage in the face of uncertainty.

Fish and Wildlife Program

One final important piece of the Council's power plan is the development of the Council's fish and wildlife program pursuant to Section 4(h) of the Act. Specifically, Section 4(h) requires that the Council, "prior to the development or review of the plan, or any major revision thereto," call for recommendations from state and federal fish and wildlife agencies and tribes and adopt or amend a program to protect, mitigate, and enhance fish and wildlife, including related spawning grounds and habitat, affected by the development and operation of any hydroelectric facilities on the Columbia River and its tributaries. The fish and wildlife program process is heavily circumscribed, with the recommendations requested at the start of the process becoming the base from which the Council builds the program.

Per Section 4(e), the Council's fish and wildlife program is an element in the Council's power plan, and the Council has an obligation to develop the power plan's resource strategy with due consideration for the protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish. Additionally, pursuant to Section 6 of the Act, Bonneville has an obligation to acquire sufficient resources consistent with the Council's plan to not only reduce or meet the administrator's obligations but to also meet the fish and wildlife protection and mitigation requirements reflected in the Council's fish and wildlife program. Thus, the Council's fish and wildlife program necessarily comes before the Council's power plan so that the Council may determine the non-power constraints on the hydrosystem necessary to protect, mitigate and enhance fish and wildlife, and then use the power planning process to assure an adequate, efficient, economical, and reliable power supply for the region. Sections 11 and 12 further discuss the integration and consideration of the fish and wildlife program.

Supporting Materials

Throughout this power plan, there are references to supporting materials–information, data, and analysis–that provide the basis for the conclusions, recommendations, and explanations in the plan. For example, Section 5 describes the conservation program, which is a required element of the power plan; however, sitting beneath Section 5 in the supporting materials is data and analysis to inform the conservation program, including the Council's methodology for estimating the energy efficiency resource potential for the region, estimated energy efficiency potential by sector, as well as the energy efficiency supply curve bins and workbooks. For another example, Section 6 provides the resource strategy, and sitting beneath that section are supporting materials providing detailed information and analysis on the existing system, potential system needs, and resource costs developed in the supporting materials. These are just a few examples of the data and information found in the supporting materials that support the power plan's recommendations and explanations addressing each of the required elements outlined in the Power Act. The supporting materials are available for review at: nwcouncil.org/2021powerplan_sitemap

Section 3: Demand Forecast

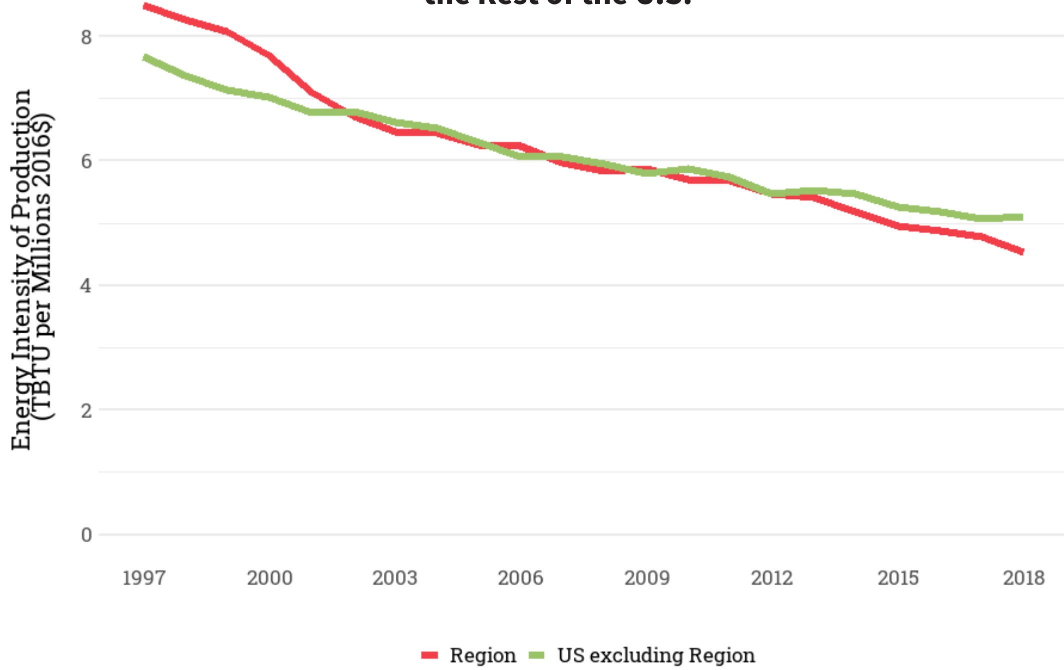
The Evolving Role of Electricity in the Northwest

Electricity is so ubiquitous it's often overlooked. Our economy would hardly function without electricity. But increasingly, society is looking to electricity as a solution to reducing greenhouse gas emissions. Whether in electrification of light-duty vehicles or reducing fossil-fuel use in industrial applications, the use of electricity is broadening rapidly. At the same time, technologies like LED lighting have greatly increased the efficiency of long-standing uses for electricity.

The Northwest historically had industries with higher energy consumption than the rest of the United States, but that shifted over the last couple of decades. Now the regional consumption of energy is lower than the rest of the United States per dollar of production.

Increasing the efficiency of our energy use and expanding the electricity available at a

Energy Intensity of Regional Production is Falling Faster than the Rest of the U.S.



reasonable cost helps both grow the regional economy and accomplish the region's goals for reducing greenhouse gas emissions. An important requirement of the power plan is the development of a demand forecast. The Council develops a demand forecast for both electricity and natural gas use in homes and buildings and examines both risks and opportunities in its forecast.

Potential New Sources of Load

Transportation – the movement of people and goods – is a large energy consumer. According to the U.S. Energy Information Administration, as much as 28 percent of all the energy consumed annually is for transportation, and most of that energy is delivered from petroleum-based fuels like gasoline and diesel. As a result, total greenhouse gas emissions from the transportation sector have reached parity with the emissions associated with electricity generation. Light duty plug-in electric vehicles provide better efficiency and lower fuel and maintenance costs than their gasoline counterparts and are gaining favor with the consumer. Electric passenger vehicles are also gaining favor with state clean policymakers as the vehicles have zero tailpipe emissions and are poised to disrupt the automobile and petroleum-product business models over the next decade.

For the 2021 Power Plan, we have developed a forecast of transportation and its related fuel usage. In the near term, the electrification of light duty cars, trucks, and vans results in cleaner and more efficient use of energy. Over the longer term (more than 10 years), heavy-duty vehicles, like long-haul trucks, offer further opportunity to electrify. Heavy vehicles are more challenging for plug-in battery technologies. The development of hydrogen fuel-cell powered trucks may become key for continued electrification of transportation, and the associated production of hydrogen required to fuel these vehicles could result in significant growth in the demand for electricity in the region.

The Council recommends policymakers and utilities that are pursuing regional emissions reductions utilize strategies that increase the adoption and use of zero- or low-emission vehicles. Battery electric vehicles are especially suited to meet passenger car and light truck requirements. Consumers in some areas within the region may be more concerned with range anxiety related to reduced battery electric vehicle performance in severe cold weather. Plug-in hybrid vehicles with gasoline engine range extenders, or hydrogen fuel cell vehicles may provide a better option. The hybrid and fuel cell vehicle technologies may also provide a solution for some heavy-duty vehicles like delivery trucks and large freight trucks. As these strategies are pursued, we recommend working with the Council, other regional bodies, and power planners to ensure an adequate electric system through the vehicle stock transition.

Direct Use of Natural Gas Forecast

To form a more comprehensive understanding of expected regional emissions, we forecast the need for energy end-uses like transportation or space heating. An end-use is the need or purpose that is served by energy, such as electricity delivered over the electric distribution system, gasoline bought from a fueling station, or natural gas delivered by a pipe to a home or a business. We then estimate the proportion of the different end-uses that are served by different types of fuel. A residence can be heated either by a heat-pump that uses electricity or a furnace that burns natural gas.

End-use consumption of natural gas tends to be seasonal, with peaks in the winter months and lulls in the summer. Homes with gas hookups are the largest consumer of natural gas. Many residences use a gas furnace for heating during the winter, and roughly 75 percent of the residential usage occurs in the months of November through March. Overall, the forecast is showing slight growth in the end-use of natural gas through the planning horizon; roughly 0.5 percent per year on average.

Renewable Natural Gas

Renewable Natural Gas (RNG) is biogas that has been conditioned and upgraded so that it can directly displace fossil natural gas. The ability of RNG to replace fossil natural gas use is limited in scope – recent studies suggest that regionally produced RNG could replace less than 10 percent of the natural gas end-use demand.[2] For this power plan, the Council modeled a blended RNG/fossil gas supply as part of the forecast for end uses. This blend reflects the impact of regional RNG supply entering the existing natural gas pipeline system and displacing conventionally sourced fossil natural gas that is currently imported from Canada and the U.S. Rocky Mountain region.

The end combustion of RNG emits CO_2 just like fossil natural gas, and it is not always a net zero carbon product as its carbon intensity varies by feedstock. RNG, however, generally provides a lower carbon footprint than fossil natural gas. RNG that is produced from organic waste streams that

Forecast of End-Use Natural Gas Consumption

Units in TBTU	2020	2025	2030	2035	2040	2045
Total Natural Gas	478	476	460	508	510	533
Fossil Natural Gas	478	473	451	487	479	492
Renewable Natural Gas	0	2	9	21	31	41

2 nwcouncil.org/2021powerplan_renewable-natural-gas

would otherwise release methane directly may be especially beneficial because the warming potential of methane is over 80 times that of carbon dioxide over a 20-year timeframe. RNG that displaces natural gas use can also reduce upstream methane emissions associated with the extraction and transportation of fossil gas. Reliable, locally sourced RNG could also help reduce gas price volatility.

The Council recommends incorporating renewable natural gas into utility and other regional long-term planning, including identifying the least-cost and lowest net emission profile projects to produce renewable natural gas that may be blended into the gas system. The Council also recommends regional utilities support renewable natural gas, when appropriate, as a method to reduce end-use natural gas emissions, supply low-carbon fuel for transportation, and provide diversity and price stability with a regionally sourced fuel product.

The Impact of Climate Change on the Use of Electricity

When looking at the impact of climate change on the use of electricity, the Council considers both the direct and the indirect effects. The direct effects look at existing buildings and businesses and their current equipment that uses electricity and estimates the impact of changing temperatures and precipitation on the amount of electricity needed. For example, as temperatures increase, the air conditioning equipment currently installed at homes and businesses uses more electricity.

To estimate the direct impact of climate change on the use of electricity, the Council uses temperature projections downscaled for our region from three different General Circulation Models.[3] These models were selected to represent a broad range of possible conditions associated with an increased concentration of greenhouse gasses in the atmosphere.[4]

The indirect impacts of climate change look at decisions or events where we anticipate different outcomes because of climate change. For example, more people moving to the region from hotter climates increases

3 The three models selected were CanESM2, CCSM4, and CNRM, further details on these models and the selection process can be accessed using the link for the supporting material at the end of this section

4 For more information on the River Management Joint Operating Committee efforts on downscaling General Circulation Models see: www.bpa.gov/p/Generation/Hydro/Pages/Climate-Change-FCRPS-Hydro.aspx

the population. The increase in population in turn increases the need for energy.

To estimate the indirect effects of climate change, the Council examined a broad range of sources and consulted with regional experts on climatic and demographic data. These data needed both sufficiently detailed projections and near-term impacts that fit within the 20-year forecast period we include in this plan. They also needed to be related to the demand for electricity.

Direct Impacts of Climate Change

The models we use to estimate the need for electricity estimate the number of days the region is likely to use cooling or heating for buildings. These are represented as Cooling Degree Days and Heating Degree Days.[5] Fewer heating degree days means that there is less

Projection of Average Heating and Cooling Degree Days for each Global Climate Model

	Heating Degree Days			Cooling Degree Days		
	2020-2029	2030-2039	Decrease	2020-2029	2030-2039	Increase
CanESM2						
Oregon	4409	4116	6.7%	451	486	7.8%
Washington	4669	4350	6.8%	364	403	10.9%
Idaho	5726	5398	5.7%	785	815	3.8%
Montana	6965	6527	6.3%	410	423	3.2%
CCSM4						
Oregon	4542	4417	2.7%	385	401	3.9%
Washington	4847	4717	2.7%	299	327	9.1%
Idaho	5892	5534	6.1%	641	746	16.3%
Montana	7242	6966	3.8%	330	393	19.1%
CNRM						
Oregon	4686	4222	9.9%	371	450	21.4%
Washington	4962	4482	9.7%	309	358	15.9%
Idaho	6073	5499	9.5%	673	713	5.9%
Montana	7378	6721	8.9%	353	362	2.6%

5 Cooling Degree Days are calculated by adding up the degrees above 65 degrees Fahrenheit of the average daily temperature for each day in the period being examined. Heating Degree Days are calculated similarly by

of a heating need in the winter, lowering the use of energy. Whereas, more Cooling Degree Days means that there is more energy needed in the summer.

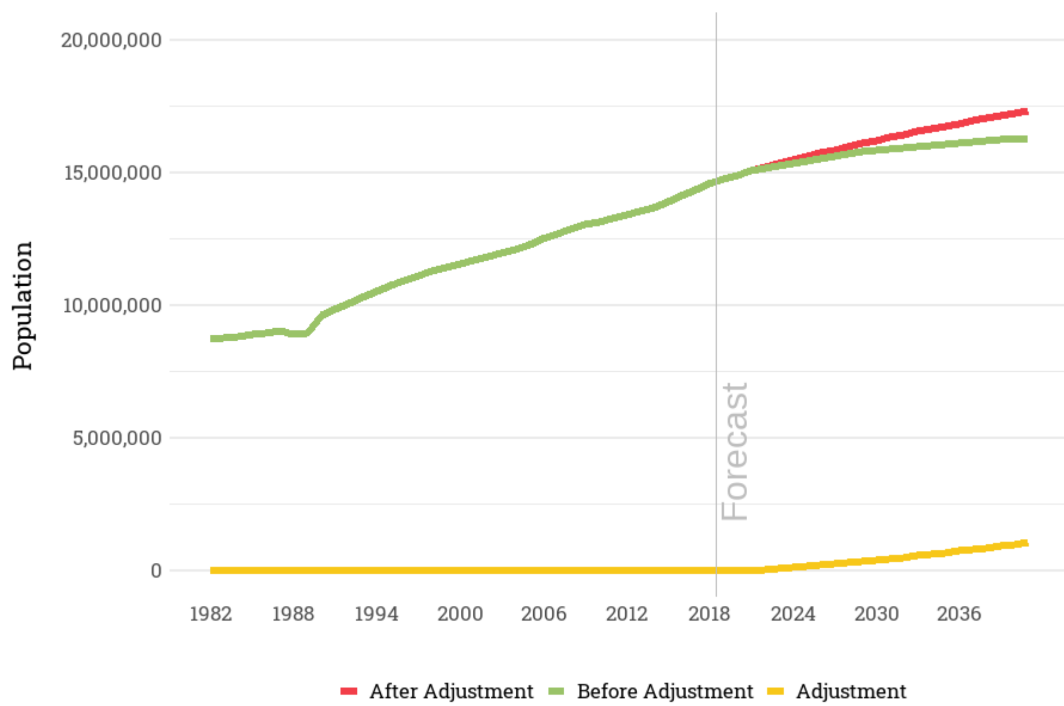
Projection of Average Heating and Cooling Degree Days for each Global Climate Model

Another direct impact of climate change we anticipate is a change in regional precipitation. Our models look at the electricity used to pump water for agricultural irrigation. The use of electricity for agriculture and irrigation averaged about 690 average megawatts per year between 1986 and 2018. With more precipitation, less water needs to be pumped to fields for irrigation which, in turn, uses less energy. With less precipitation, the opposite holds, and more energy is used. However, an increase in irrigated land based on increasing regional population is included in our forecast as an indirect effect of climate change.

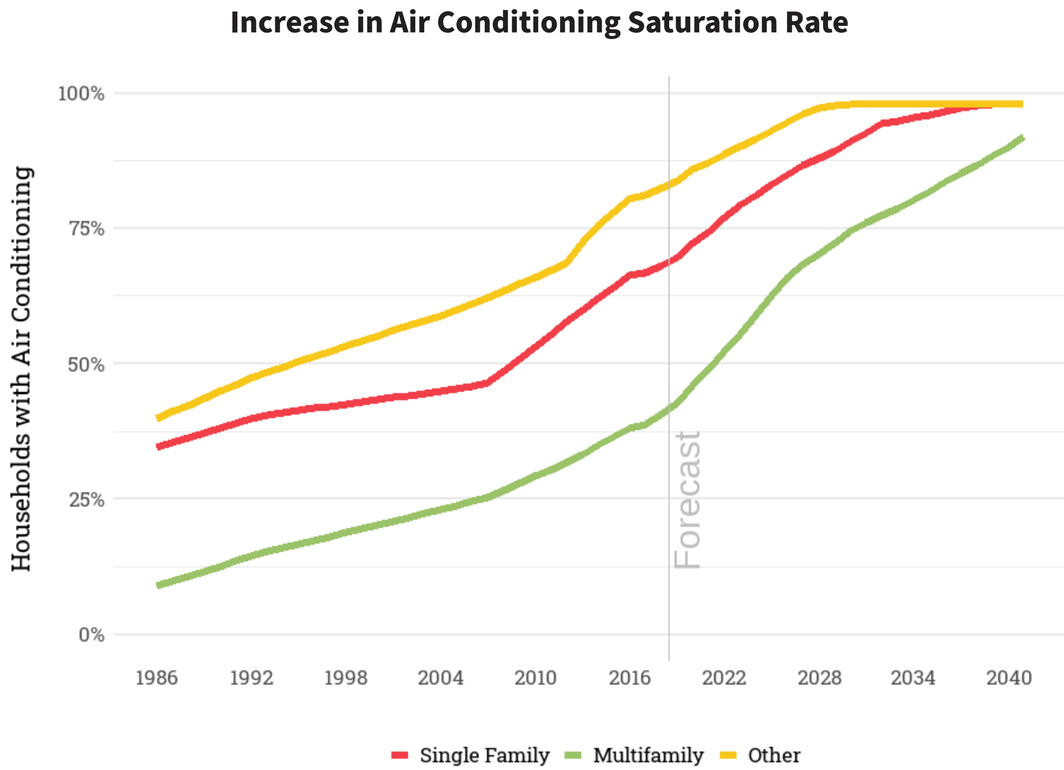
Indirect Impacts of Climate Change

There are many indirect impacts of climate change that could impact the demand for electricity. Events like flooding and wildfires with destructive effects on buildings and infrastructure that use electricity are difficult to forecast and quantify. In those cases,

Regional Population Adjustment for Indirect Climate Change Impacts



adding up the degrees below 65 degrees Fahrenheit of the average daily temperature for each day in the period being examined.



we are unable to incorporate the potential impacts into our demand forecast but acknowledge these are potential impacts to electricity use in our region that deserve continued study.

Some effects of climate change are easier to estimate. Where it has been possible to do so in a robust manner, we have included those impacts in our forecast. One adjustment we made is an increase to forecast population. Studies looking at the impact of climate change on migration[6] show a net increase in regional population. Using these studies, we have adjusted population projections in our forecasts.

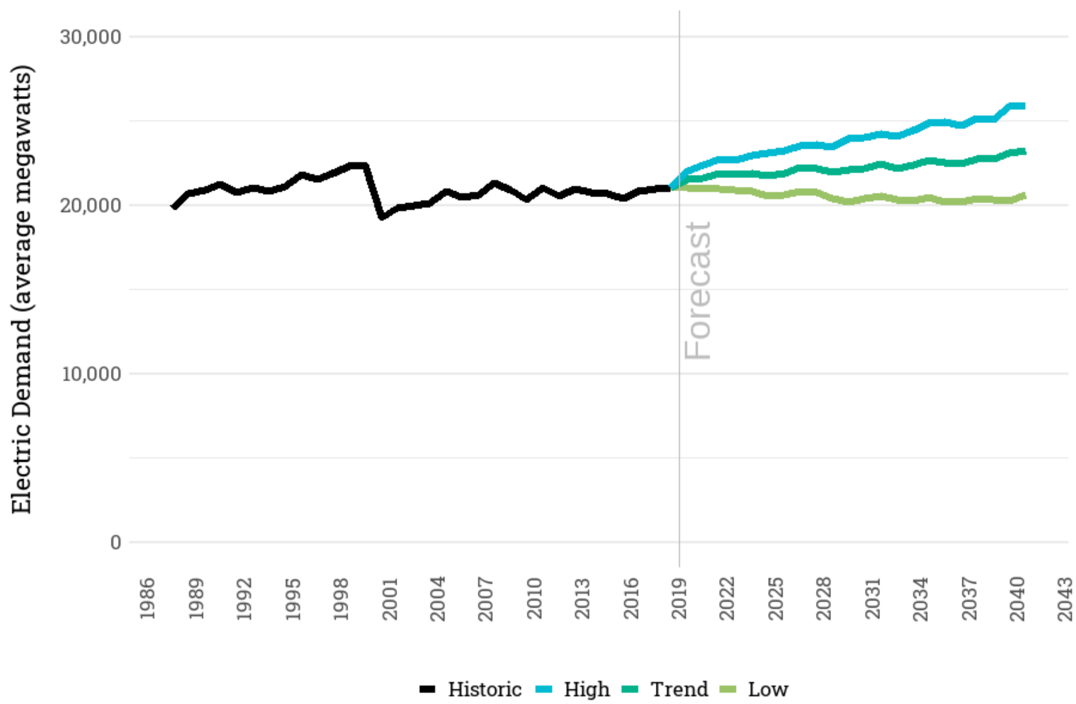
We also adjusted the saturation of air conditioning in new construction for the region. We have seen a growing penetration of air conditioning installed in residential construction. With climate change, we see that penetration continuing to climb and have adjusted our forecasts to grow to a 98 percent penetration by 2050.

Forecast of Regional Demand for Electricity

Over the next 20 years, the Council forecasts the demand for electricity will be driven by many factors including economic growth,

6 For detailed information on the studies and the population adjustment, see the supplemental material link at the end of this section.

Range of Regional Demand for Electricity Based on Economic Conditions



climate change, regional demographics, and expanding applications of electricity to reduce the use of fossil fuels. With all these considerations, we realize that no single forecast could appropriately capture the risks and opportunities to consumers and suppliers of electricity. To better assess the impact on the region, we forecast a possible range for electricity demand.

These forecasts are more uncertain further into the future. To some extent that is considered when we use a range in our analysis. However, our ability to predict what will drive demand for electricity has limits. Thus, the Council updates our forecasts as we get new information. Our forecasts in this power plan are updated and do not match the forecasts included in the last power plan. It should be expected that forecasts beyond the first 5 or 6 years could be missing key drivers that lie outside what would be considered a reasonable forecast at this time. Those drivers will be much clearer in the power plan that follows this one. The Council also forecasts based on current state and federal legislation and does not attempt to predict future legislative change. While recent experience demonstrates it is unlikely that there would be no legislation impacting the use of energy over the next 6 years, exploring this type of uncertainty is left to our scenario analysis. Our scenario analysis includes an examination of added demand for electricity driven by policies or activities aimed at reducing greenhouse gas emissions. Details of our scenario analysis are included in the *Section 6 Resource Development Plan*.

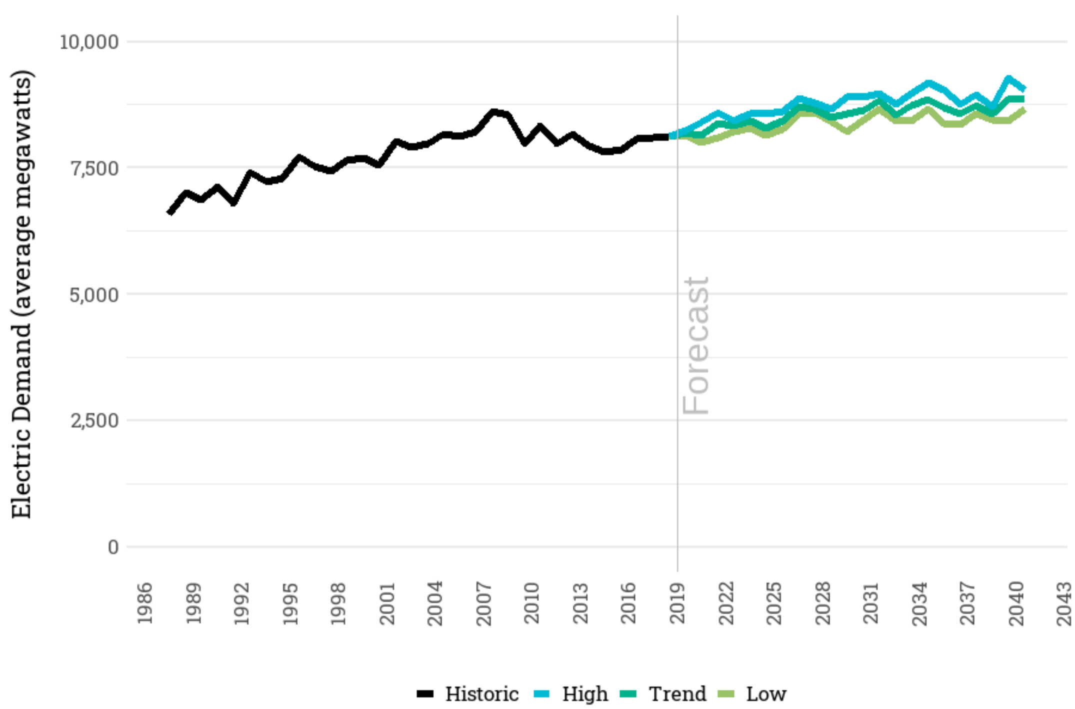
For economic growth, we forecast a range of conditions with a pessimistic estimate of around -8% and an optimistic estimate of +7%. Higher economic output drives higher use of electricity, and so demand for electricity is highest in the optimistic estimate. During the action plan period, the range of uncertainty is lower, + 4% and -5%.

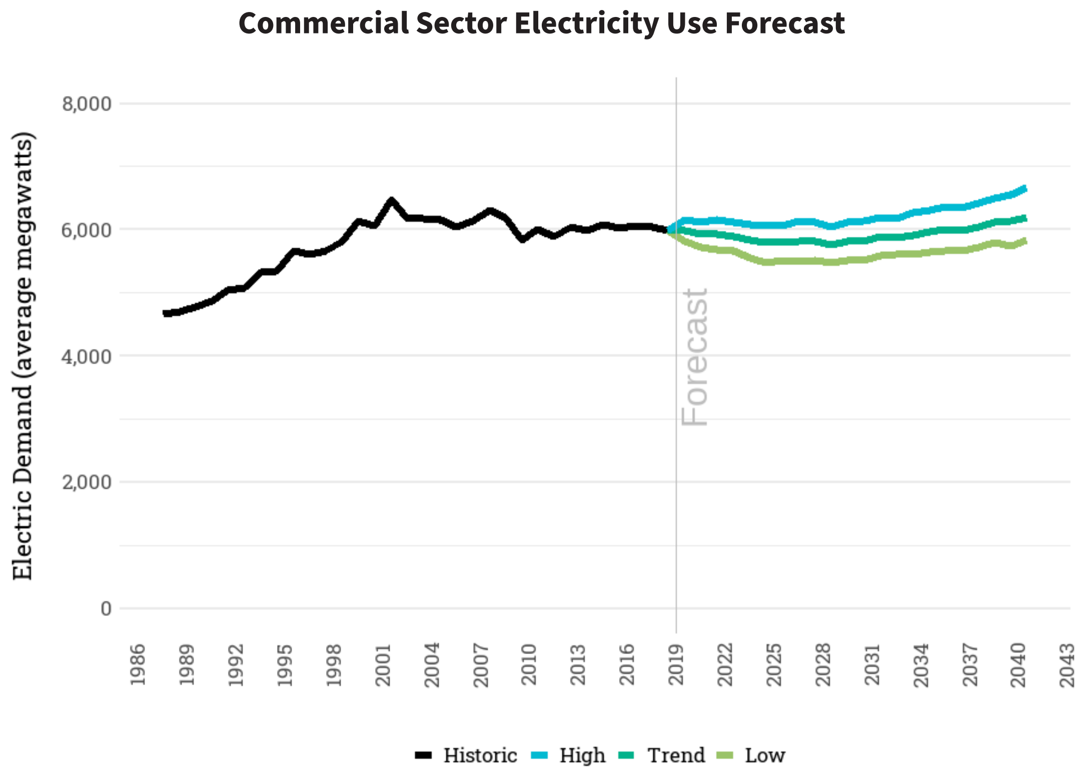
The Council uses this forecast to estimate what additional resources and reserves are adequate to supply the region's need for electricity.

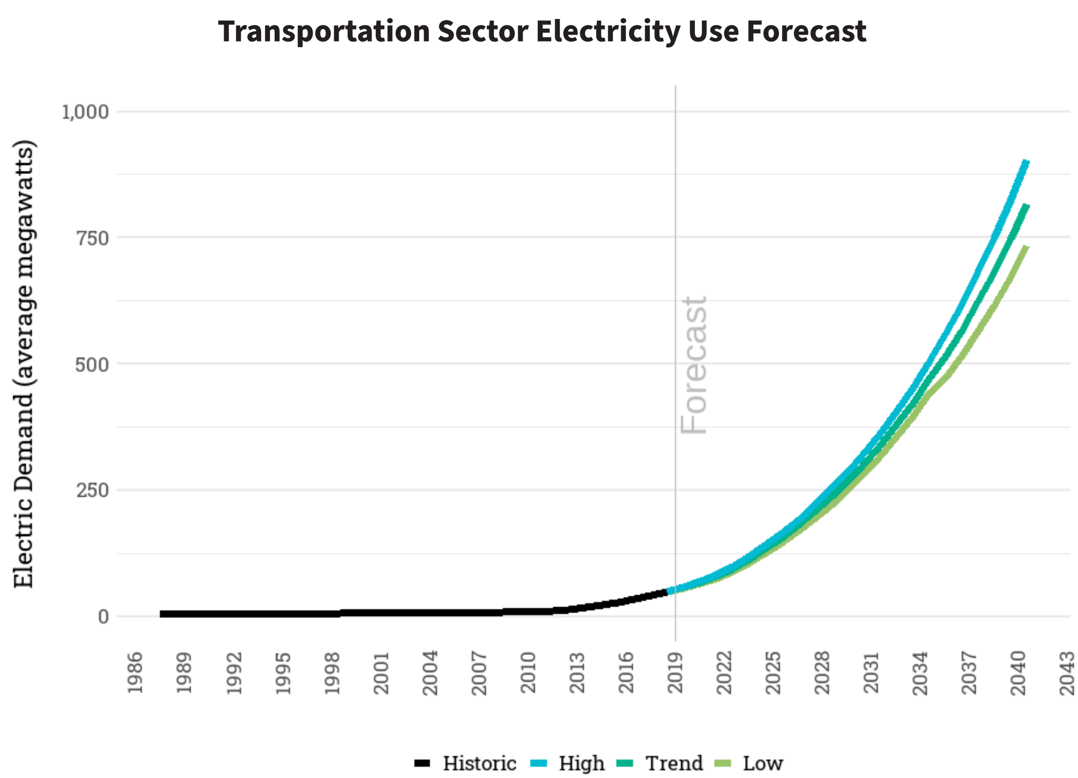
Demand by Sector

The Council's forecast is an end-use forecast. That is, it starts with the different uses for electricity, e.g., lighting or drying clothes, and builds up to sector-level forecasts. We anticipate a range of future loads. We estimate different economic and demographic drivers and then incorporate simulated temperatures from general circulation models. Including these temperatures means the forecasts are not smooth like forecasts that do not include weather variation. For example, anticipated energy needs for the residential sector are particularly sensitive to temperature variation. The loads range from 8,014 average megawatts to 9,726 average megawatts. An

Residential Sector Electricity Use Forecast




Commercial Sector Electricity Use Forecast
Electric Demand (average megawatts)
8,000
6,000
4,000
2,000
0
Forecast
1986
1989
1992
1995
1998
2001
2004
2007
2010
2013
2016
2019
2022
2025
2028
2031
2034
2037
2040
2043
Historic
High
Trend
Low


Transportation Sector Electricity Use Forecast
Electric Demand (average megawatts)
1,000
750
500
250
0
Forecast
1986
1989
1992
1995
1998
2001
2004
2007
2010
2013
2016
2019
2022
2025
2028
2031
2034
2037
2040
2043
Historic
High
Trend
Low

average megawatt[7] represents one megawatt of load for a full year. But the minimum and maximum happen in different years. While this means that each year may not reflect a specific likelihood of a load above or below our forecast, the use of these loads as a way of testing different resource strategies and helps highlight the natural variation in electricity use that will happen with different temperatures.

By contrast, the commercial sector load forecast shows less variation based on weather. The range of the commercial load is forecast to vary from around 6,000 average megawatts in the near-term to a high of around 7,359 average megawatts.

Industrial loads in our forecast range from a low of under 4,000 average megawatts to a high of just shy of 8,000 average megawatts. Irrigation loads are anticipated to grow to a range of 937 average megawatts to 1,734 average megawatts. Municipal loads like street lighting are anticipated to stay flat or decline at or under 300 average megawatts.

Our forecast also includes a quickly growing regional electric load in the transportation sector and for data centers. In the case of transportation, we anticipate substantial growth relative to the amount of electricity used today. Whereas with data centers, we've seen substantial regional growth already that we are projecting will continue.

Taking the whole picture together creates a regional forecast for the use of electricity that shows a range of energy needs anywhere from 20,580 average megawatts to 25,895 average megawatts in 2041. The table below shows the range of loads in 2041 by the different sectors compared to the expected load in 2021. These forecasts have

Forecast Range of Electricity Use in Average Megawatts by Sector

Sector Forecast	Expected Electricity Use in 2021	Forecast Electricity Use in 2041		
		Low	Medium	High
Residential	8148	8674	8860	9049
Commercial	5938	5833	6202	6673
Industrial	6186	4147	5892	7541
Transportation	67	733	816	904
Street Lighting and Water Services	271	252	280	303
Irrigation	1016	941	1164	1465
Data Centers	657	952	1179	1369

7 For context on what you can power with a megawatt see nwcouncil.org/news/megawatt-powerful-question

interactive effects so they do not add to the same range of loads as the total regional load, but they should give a sense of which sectors have more uncertainty and how they are anticipated to change throughout the forecast.

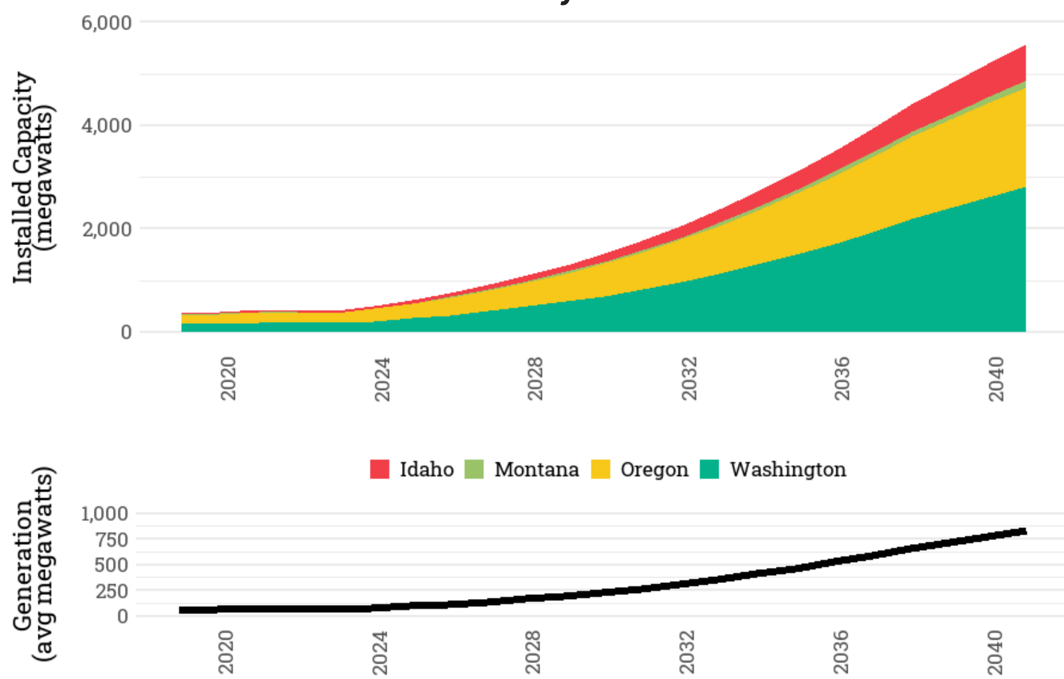
The Impact of Rooftop Solar on the Demand for Electricity

The Council's forecast includes an outlook for behind-the-meter solar installations in the region, which are generally rooftop-mounted systems in the residential, commercial, and industrial sectors. Solar panels are relatively simple to install and operate on homes and businesses. The cost to install and operate home solar has significantly declined and it is expected to continue to decline in our forecast.

Behind-the-meter solar installations in the Northwest have tripled in the five years from 2014 through 2018. By the end of 2018, nearly 90 percent of the 326 megawatts of overall capacity in the region was installed in Oregon and Washington.

The forecast for solar from our model is fairly aggressive. Because of cost declines, we anticipate the growth of installations could be rapid. The graph below shows our forecast of behind-the-meter solar installations by state for our region.

Forecast of Behind-the-Meter Solar Installed Capacity and Generation by State



Section 4: Forecast of Regional Reserve and Reliability Requirements

The fundamental objective of power system operations is to continuously match the supply of energy from electricity generators to customers' electrical demand at all times. This involves proper long-term planning to ensure that the power supply has sufficient generating capability, and that the transmission system can deliver that power within an acceptable range of frequency[8] and voltage.[9] The United States Federal Energy Regulatory Commission (FERC) defines ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas[10] and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."

8 Frequency is controlled by maintaining a stable net interchange between neighboring balancing authority areas. The basic test of success for this is called the Area Control Error (ACE). ACE is a measurement, calculated every four seconds, based on the imbalance between load (demand for electricity) and generation within a balancing area, taking into account previously planned imports and exports and the frequency of the interconnection. The North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards govern the amount of allowable deviation of the balancing authority's ACE over various intervals, although the basic premise is that ACE should be approximately zero. The ACE is maintained through a combination of automatic and operator actions. The automatic part is done through a computer-controlled system called Automatic Generation Control (AGC), which monitors the frequency of the system and correspondingly adjusts participating generators' output (within seconds) to bring the frequency back in line.

9 Voltage can be controlled in several ways with different types of system components installed at generating stations and the transmission system.

10 Control areas (also referred to as Balancing Authorities) are entities, often utilities, that ensure the power system demand and supply are balanced on a section of the electric grid. When supply and demand become too far out of balance, equipment on the transmission and distribution system will disconnect creating local or widespread electric power outages.

In general, ancillary services provide frequency and voltage control, load-following capability,[11] short-term protection for system component outages and flexibility to cover daily, hourly, and moment-to-moment variations in the electrical demand and generation.

While the fundamental objective will not change, the electricity grid seems poised to go through a paradigm change with an increasing penetration of new variable renewable generation displacing an increasing amount of the electricity that would have otherwise been generated by the existing fossil-fuel-based thermal generating fleet. The region and the rest of the West in the future will likely need to rethink how system capacity needs are measured and what different resources accomplish in providing for those needs.

Power Act Definition of Reserves

The Northwest Power Act defines reserves as "the electric power needed to avert particular planning or operating shortages for the benefit of firm power customers of the Administrator… (A) from resources or (B) from rights to interrupt, curtail, or otherwise withdraw, as provided by specific contract provisions, portions of the electric power supplied to customers." Electric power that averts operating shortages (operating reserves) falls into four general categories and are either spinning (available for immediate dispatch) or non-spinning (must be at full output within 10 minutes).

- Regulation reserves – provide minute-to-minute increases or decreases in generation to match electrical demand
- Load following reserves – bridge the gap between regulation reserves and hourly energy markets
- Balancing reserves – cover within-hour variations in electrical demand, and variations in wind and solar generation
- Contingency reserves – provide short-term (up to 60 minutes) protection against system component outages (transmission and generation)

The Council's adequacy model assigns operating reserves (regulation, load following, and balancing) and contingency reserves to appropriate resources.

What Does it Mean for a Power System to be Adequate?

While the terms "adequacy" and "reliability" are related, they have specific and distinct

11 In the utility industry, the electrical demand is often called load. Load-following refers to a service provided by electric generators that increases or decreases the output of electricity to match the use of electricity.

meanings for power system planning. A power system is defined to be reliable if it is both adequate and secure, where adequacy generally refers to having sufficient generating capability and security generally refers to having a robust transmission system.

- An adequate power system can supply the aggregate electrical demand of all customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements, and
- A secure power system can withstand sudden disturbances, such as electrical short circuits or unanticipated loss of system elements

The Council uses assumptions established by transmission planning organizations to estimate the ability to deliver electricity around the Western electric grid. However, substantial retirements or additions of generation on the system may go beyond the scope of these limits. The Council in our work assumes that transmission planning organizations and utilities will work together to ensure appropriate investment is made into the transmission system to at a minimum maintain the current ability to deliver electricity around the West. While we do not study expansion of the transmission system in this plan, we recommend the region work with transmission planning organizations to explore the costs and benefits of doing so.

Council's Resource Adequacy Standard

One of the key objectives of the Council's power plan is to develop a resource acquisition strategy that will ensure the region of an adequate, efficient, economical, and reliable power system, while taking uncertain future conditions into consideration.

The Council's overarching goal for its adequacy standard is to *"establish a resource adequacy framework for the Pacific Northwest to provide a clear, consistent, and unambiguous means of answering the question of whether the region has adequate deliverable resources to meet its load reliably and to develop an effective implementation framework."*

The standard has been designed to assess whether the region has sufficient resources to meet growing demand for electricity in future years. This is important, because it takes time – usually years – to acquire or construct the necessary infrastructure for an adequate electricity supply.

The metric used to measure resource adequacy is the annual loss-of-load probability (LOLP). The LOLP is assessed by simulating the operation of a future year's power system many times with different combinations of river flows, temperatures,[12] wind and solar generation, and generator forced outages. Whenever demand for electricity is not served, it is considered a shortfall event. The LOLP is calculated as the number of simulations in which at least one shortfall event occurred divided by the total number of simulations. The Council deems the power supply to be adequate if the LOLP is 5 percent or less. That is, the power supply is adequate if the likelihood of having one or more shortfalls in an operating year is 5 percent or less.

Method for Assessing Regional Power System Needs to Maintain Adequacy

The Council uses its evaluation of the adequacy of the existing system to establish a method for assessing potential regional power system needs to maintain resource adequacy under a broad range of different scenarios and conditions. In projecting how the region could meet these system needs we evaluate both the magnitude of those needs and the varying capability of different generating technologies or demand-side resources to meet them.

Gaps Between Existing System Capabilities and Anticipated Future Requirements

Using the Council's adequacy standard, the needs to maintain adequacy are defined as any gaps between existing system capabilities and anticipated future requirements that fall outside that standard. The existing system capabilities are evaluated on an hourly basis accounting for operational and fueling limitations, in addition to generating or demand-reduction capability for all the resources in the existing regional power system. The anticipated future requirements incorporate both regional demand and reserve requirements. The gaps between existing system capabilities and anticipated future requirements are evaluated for each quarter, which broadly can be defined as the fall, winter, spring, and summer seasons using a broad range of estimated hydro conditions, electrical demands, and renewable generation output.

The methodology to identify the size of shortfall events that need to be addressed to maintain adequacy is as follows:

1. The shortfall events in our simulations are sorted from highest magnitude to lowest magnitude on an annual basis, including the simulations where we have no shortfall events or the magnitude of the shortfall event is zero.

12 Temperatures impact the amount of electricity used; for example, during extremely hot days the regional needs more electricity for air conditioning

2. The top 5 percent of the simulated shortfall events (those of the highest magnitude) are assumed to be acceptable under the Council's standard. We do not consider these further.

3. We take the highest magnitude shortfall events remaining for each season as the gap between the existing system capabilities and anticipated future requirements necessary to maintain the Council's adequacy standard. If there are shortfalls greater than zero in more than 5 percent of the simulations, then these seasonal gaps will be non-zero.

The size and composition of the gaps varies between scenarios. When we implemented the climate change projections into the analytics that support the plan, we have projections on temperatures and precipitation going into the future. These projections are not intended to be used as what the expected weather will be in any individual future year, rather they illustrate the types of temperatures that can be expected and the data are designed so that the range of weather over each decade represents an estimate of the range of conditions driven by climate change. The following table shows the maximum energy need (in average megawatts) with the decade for the calendar quarters[13] generally associated with winter and summer. This helps illustrate how much the needs varied between the different scenarios explored in this plan with some scenarios showing substantial needs even within the

Highest Decadal Increment Energy Needs for Select Scenarios (average megawatts)

	2022 to 2029	2030 to 2041
July to August – Early Coal Retirement		
Average	1071	1429
Maximum	2987	3579
January to March – Early Coal Retirement		
Average	1008	1393
Maximum	2884	3648
July to August – Partial Decarbonization		
Average	2461	11120
Maximum	5201	15689
January to March – Partial Decarbonization		
Average	2857	9578
Maximum	6012	14420
July to August – Organized Markets		
Average	0	1
Maximum	0	189
January to March – Organized Markets		
Average	14	742
Maximum	514	2744

13 Our Regional Portfolio Model uses estimated distributions of hourly loads for each calendar quarter. It is certainly possible to have a heat event in June or a cold event in December. These are included in the analysis but not explicitly listed here for the sake of brevity.

2020s. We discuss the gaps resulting from this method for different scenarios in *Section 6: Resource Development Plan*.

Future Resource Capability to Fill Gaps

When exploring the capability of future resources or reserve additions to fill the gap described above, the Council evaluated the attributes of each resource and how they interacted with the existing system to change the total regional capability to meet anticipated future requirements. The existing system, including the region's hydropower generation, can adapt in different ways that fill these gaps. When adding resources that increase the need for reserves, like wind and solar generation, it may reduce the existing system's peak capability.

The ability of the regional hydropower system to support the regional electric grid in different ways is a valuable attribute. However, the demands on the system must be balanced, making sure not to double count the contribution of these resources. Further, the regional hydro system has many purposes beyond generating electricity that take priority and must also be accounted for in any future projections of what the power system can rely on from these resources. The Council models reserves required from both the existing system and any new resources to capture this important dynamic. The examination of future resource characteristics included operational and fueling limitations on an hourly basis in addition to generating or demand-reduction capability within the context of the existing regional power system.

To determining how a resource or combination of resources[14] fill the gaps in the existing system capabilities, we:

1. Simulate the regional power system in 2031 with high demand, all the regional coal units retired, and no new resource additions, then record the maximum gap between existing system capability and system obligations.

2. Simulate the regional power system in 2031 with high demand, all the regional coal units retired, and with a combination of new resource additions. Then record the maximum gap between existing system capability and system obligations.

3. Take the difference in the gaps from the simulations step 1 and 2 and divide that difference by the total nameplate resource additions from the combination of new resources in step 2.

4. Use that percentage as a multiplier when assessing the capability of a combination of new resources to meet any identified gaps.

14 For all combinations not explicitly tested, a multilinear interpolation allows the capability of any new combination of new resources considered in the resource strategy analysis to be identified and considered when attempting to address gaps associated with peak conditions.

Section 5: Energy Conservation Program

Background on Energy Efficiency in the Northwest

Energy conservation is defined in the Power Act as "any reduction in electric power consumption as a result of increases in the efficiency of energy use, production or distribution."[15]

In recent years, the Northwest region's utilities have spent about $480 million dollars per year on energy efficiency. This includes investments in incentive programs, market transformation initiatives, evaluation, and research such as in market research, building stock assessments, and emerging technologies. Estimates indicate that in our region, over 100,000 people are employed working with energy efficiency at utilities, the Northwest Energy Efficiency Alliance (NEEA), the Energy Trust of Oregon, state agencies, and at the many trade allies and contractors that work to implement programs and deliver efficiency services.[16]

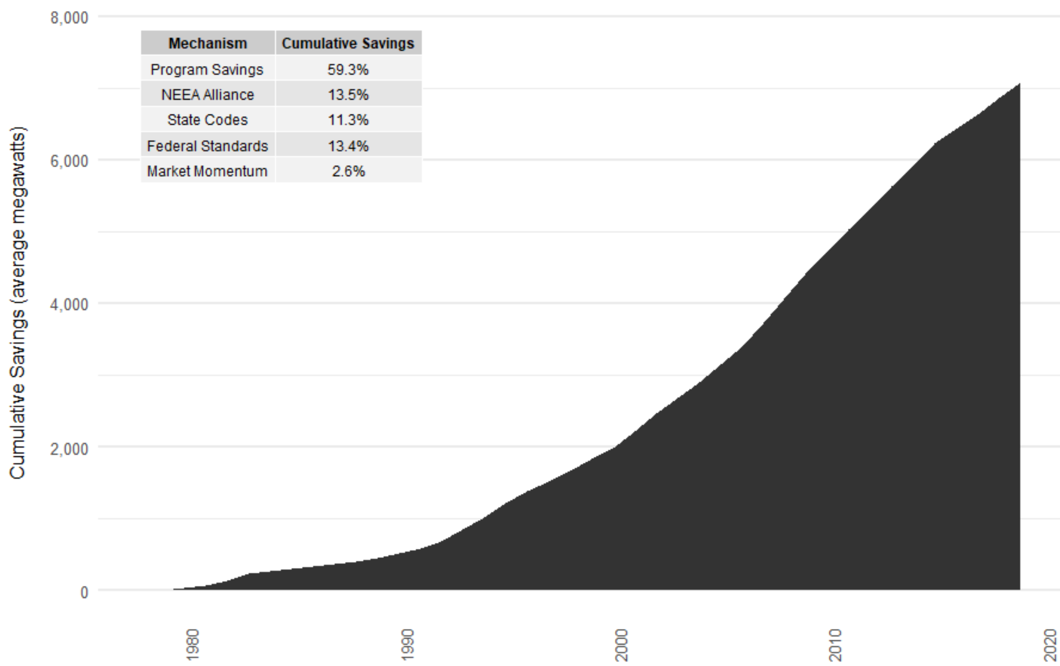
This investment has resulted in more than 7,200 average megawatts of savings since 1978. About 60 percent of those savings are from direct utility program incentives.[17] The remainder is from NEEA market transformation initiatives, improvements in codes and standards, and other market adoption. These savings amount to a regional resource second only in magnitude to hydropower and are equivalent to the annual energy consumption of around 5.1 million Northwest homes. By reducing electricity generation from fossil-fuel power plants, the savings have avoided more than 22.2 million metric tons of carbon dioxide emissions. The cumulative efficiency savings since 1980 have reduced consumer electricity bills by about $4 billion per year. Efficiency has also shown to provide reductions in other non-energy consumables, such as water, and provide additional benefits to consumers in the form of health, comfort, and productivity.

15 Northwest Power Act Section 3(3), 94 Stat 2698

16 U.S. Energy and Employment 2020 report www.usenergyjobs.org

17 More information on conservation achievements can be found on the Regional Technical Forum website rtf.nwcouncil.org/about-rtf/conservation-achievements/2019

Cumulative Regional Energy Efficiency Savings by Mechanism



In recent years, with all the accomplishments and increasing efficiency levels, the future amount of low-cost efficiency available has diminished. One key example is LED light bulbs that have transformed the industry; a 9-watt LED bulb provides at least as much illumination as the traditional 60-watt incandescent. These are significant savings, and future lighting improvements cannot be as profound. However, savings remain[18] in lighting and other end uses, and continued investment is needed to ensure low-cost efficiency remains available.

Regional Recommendations on Energy Efficiency

Amount of energy efficiency the region should acquire

The Council recommends that the region acquire between 750 and 1,000 average megawatts of energy efficiency by the end of 2027 and at least 2,400 average megawatts by the end of 2041.[19] The lower end of this recommended range represents cost-effective energy efficiency acquired at a

18 See New Opportunities for Energy Efficiency in Section 6: Resource Development Plan for further details.

19 More details on the basis for the level of the recommendation can be found in the supporting materials, here: nwcouncil.org/2021powerplan_Cost_Effective_Conservation_Recommendation_Summary

moderate pace, whereas the higher end of the range represents cost-effective efficiency that is acquired more rapidly.[20]

We expect that most of the short-term savings will be via direct-funded utility programs, but this recommendation also includes efficiency accomplished through market transformation initiatives through NEEA, building codes, appliance standards, and natural market adoption. Regional support of all mechanisms is needed for long term achievement and continued availability of energy efficiency.

The Council's regional recommendation includes efficiency acquired at all regional utilities, including the Bonneville customer utilities. Our specific recommendations to the Bonneville Administrator regarding energy efficiency are included in *Section 8: Recommendation for Amount of Power and Resources Bonneville Power Should Acquire to Meet or Reduce the Administrator's Obligation*.

To achieve this overall goal, all utilities within the region will need to deliver energy efficiency to their end-use customers. For utilities within urban centers, efficiency may be more readily accomplished, given greater availability of contractors and suppliers of efficient products and easier access to a large and diverse number of customers. In contrast, utilities with a rural customer base (primarily residential and agricultural) have significant challenges and fewer resources for implementing cost-effective efficiency programs. These challenges are recognized, and Bonneville and/or other regional organizations such as NEEA should support these rural utilities in reaching efficiency goals.

Continued investment in NEEA and efficiency-related research and development[21] is critical to achieve the long-term goals. To help ensure a robust efficiency infrastructure, work is needed all along the product adoption curve: Continuing research into emerging technologies to introduce new efficiency opportunities; working with retailers and manufacturers to increase the availability of efficient products; and encouraging acceptance by consumers. NEEA and utilities will need to be diligent in ensuring progress in all these facets of the market. As such, to help ensure that the necessary levels of cost-effective conservation are acquired, we recommend the region's utilities:

1. Maintain ratepayer-funded efficiency programs (utility direct programs and market transformation initiatives) at a funding level sufficient to achieve the 2027 goals;

20 The cost-effectiveness methodology for conservation can be found here: nwcouncil.org/2021powerplan_cost-effective-methodology

21 See Section 10: Recommendations for Research and Development for more discussion on this topic.

2. Continue to fund research and development on emerging technologies in an amount commensurate with 2020 levels or greater;

3. Continue to fund regional market research, stock assessments, and related analysis in an amount commensurate with 2020 levels or greater;

4. Support initiatives to enhance building codes and appliance standards, at both the state and federal government-level.

In addition to the amount accomplished under the target, we recommend the region continue to invest in weatherization programs, targeting those homes that are leaky (in need of duct or air sealing) and/or have zero or limited insulation. These measures are critical to provide livable homes for all people.[22] Much of this work is currently being accomplished through low-income weatherization programs, co-sponsored by utilities and state and federal agencies. However, there may be homeowners or renters who do not qualify under those programs but live in substandard housing, and utilities should strive to weatherize those structures as well. In some cases, the structures' needs may be beyond weatherization services, and home replacement programs should be considered.[23] Utilities should consider coordinating with other agencies (such as community action agencies, state agencies, and/or nonprofits) and explore co-funding options to best serve these homes.

Utilities should also begin utilizing energy use intensity (EUI) data for commercial buildings to identify buildings that have consumption levels significantly higher than other comparable buildings. This approach can provide a market-sector-neutral way of identifying those customers in the greatest need of efficiency measures and otherwise previously missed by programs. For example, utility program managers have indicated (and supporting data suggest) that small commercial customers typically have higher EUIs than their larger counterparts. All customers with these higher-than-average EUIs should be targeted for implementation of cost-effective conservation.

Objectives of Conservation Programs

All conservation actions or programs should be implemented in a manner consistent with the long-term goals of the region's electrical power system, as established in the 2021 Power Plan. To achieve this goal, the following objectives should be met:

1. Conservation acquisition programs should be designed to ensure levels of efficiency that are cost-effective for the

22 Some of these measures will not be cost effective relative to the plan but should still be included in the programs.

23 For example, some utilities have programs replacing an old manufactured home with a new efficient model.

region and economically feasible for the consumer.

2. Conservation acquisition programs should target conservation opportunities that are not anticipated to be developed by consumers.

3. Conservation acquisition programs should be designed so that their benefits are distributed equitably.

4. Conservation acquisition programs should be designed to secure all measures in the most cost-efficient manner possible.

5. Conservation acquisition programs should be designed to take advantage of naturally occurring "windows of opportunity" during which conservation potential can be secured by matching the conservation acquisitions to the schedule of the host facilities or to take advantage of market trends. In industrial plants, for example, retrofit activities can match the plant's scheduled downtime or equipment replacement; in commercial buildings, measures can be installed at the time of renovation or remodel.

6. Conservation acquisition programs should be designed to capture all cost-effective conservation savings in a manner that does not create lost-opportunity resources. A lost-opportunity resource is a conservation measure that, due to physical or institutional characteristics, will lose its cost-effectiveness unless actions are taken to develop it or hold it for future use.

7. Conservation acquisition programs should be designed to maintain or enhance environmental quality.

8. Conservation acquisition programs should be designed to enhance the region's ability to refine and improve programs as they evolve.

Not all energy efficiency provides equivalent value to the regional electric system. Some distinguishing attributes, such as cost and savings shape, have been captured in the portfolio analysis. However, energy efficiency's ability to improve building resilience[24] and grid flexibility[25] is not well modeled. These attributes are important to maintaining a robust electric system infrastructure, and energy efficiency that provides these values should be prioritized,

24 Building resilience refers to the building's ability to withstand a power outage or extreme weather event. For example, a well-insulated home will maintain its conditioned temperature for longer during an outage or extreme temperatures.

25 Grid flexibility refers to a building's ability to respond to the needs of the grid. Energy efficiency that enables this flexibility could have additional value. For example, an efficient lighting system that has embedded controls could be tapped by a utility to balance the grid.

and we will endeavor to improve our estimates over the action plan period. The Council's Regional Technical Forum (RTF) should explore the mutual benefits of energy efficiency and demand response in providing grid flexibility.

Consequences of not achieving the regional recommendations

The minimum of 750 average megawatts of energy efficiency by the end of 2027 is what we have determined to be more cost-effective than pursuing other resources when considering risk and uncertainty of meeting adequacy needs, decarbonization, renewable resources availability and reliability, and future market pricing. Not achieving this efficiency may result in higher costs to the system and impede development of a more equitable energy system. This efficiency will maintain jobs, lower greenhouse gas emissions, reduce energy burdens for households and businesses, and avoid adequacy shortfalls. In developing this target, the Council also considered specific values for measures to improve a home's resilience to power outages and enable future interconnectedness with the electric grid. Thus, the cost-effective efficiency will help enable a robust electric power system. In addition, investment in measures to improve livability of poorly insulated houses will help toward achieving equity of residential energy burden.

Model Conservation Standards

The Northwest Power Act directs the Council to adopt and include in its power plan a conservation program that includes model conservation standards (MCS). The MCS are applicable to (i) new and existing structures; (ii) utility, customer, and governmental conservation programs; and (iii) other consumer actions for achieving conservation. The Act requires that the standards reflect geographic and climatic differences within the region and other appropriate considerations. The Act also requires that the Council design the MCS to produce all power savings that are cost-effective for the region and economically feasible for consumers, taking into account financial assistance from the Bonneville Power Administration and the region's utilities.

In addition to the requirements set forth in the Act, the Council believes the model conservation standards in the plan should produce reliable savings and that the standards should, where possible, maintain and improve upon the occupant amenity levels (e.g., indoor air quality, comfort, window areas, architectural styles) found in typical buildings constructed before the first standards were adopted in 1983.

The Power Act provides for broad application of the MCS. In the earlier plans, a strong emphasis was needed to improve residential and commercial building construction practices beyond the existing codes. Beginning with the first standards adopted in 1983, the Council has adopted a total of seven model conservation standards. These include the standard for new electrically heated residential buildings, the standard for utility residential conservation programs, the standard for all new commercial buildings, the standard for utility commercial conservation programs, the standard for conversions to electric heating systems, and the standard for conservation programs not covered explicitly by the other model conservation standards.[26] Since the Council adopted its first model conservation standards, all four states within the Northwest have adopted strong energy codes that largely incorporate the standards.

The MCS for the 2021 Power Plan have two main components. The first is that the Council adopts two specific components to the standards to ensure equity in efficiency adoption through codes and standards. The second component provides the standard for conversions (similar to prior MCS) to an electric space or water heating system from another fuel.

The focus of the codes and standards component of the MCS is on two areas intended to improve equity around efficiency acquisition through codes and standards. These areas include supporting common appliance standards in the Northwest and discouraging backsliding or reducing codes or standards.

In addition, as municipalities around the region are considering reducing their carbon footprint, electrification of end-use equipment has gained interest. The second component of the MCS is the standard for conversions (similar to prior MCS) to an electric space or water heating system from another fuel. The Act definition of conservation clearly excludes fuel switching as energy efficiency. However, if fuel switching were to be promoted, this MCS directs action to ensure the switching is performed with all cost-effective electric energy efficiency incorporated.

Common Appliance Standards

The minimum efficiency requirements of many appliances and equipment are regulated at the federal level.[27] These standards are a low-cost, equitable means of achieving cost-effective efficiency. For products without a federal standard, states may adopt their own minimum efficiency requirement. In the past few years, several states have adopted their own standards,

26 The 2021 Power Plan model conservation standards and surcharge methodology supersede the Council's previous recommendations.

27 www.energy.gov/eere/buildings/appliance-and-equipment-standards-program

including Washington[28] and Oregon.[29] Often, these standards are consistent with those in California, allowing for a uniform market in the western-most United States. This commonality is preferred by manufacturers to minimize regulatory confusion and multiple product lines. To further efficiency and limit market disruption, Northwest states should consider adopting common standards and work to synchronize updates. Coordinating with additional states, such as through initiatives by the Appliance Standards Awareness Project,[30] would strengthen the likelihood of compliance and manufacturer buy-in.

No Backsliding on Codes or Standards

Once a code or standard has been adopted, no state or federal agency should change the standard such that a subset of buildings or appliances are subject to a less stringent standard. Codes and standards are a low-cost, equitable means of achieving cost-effective conservation. When markets are segmented into product classes and thus subject to differing requirements, this dilutes the efficacy of the code or standard and decreases efficiency. This in turn has impacts on the ability for the region to equitably provide low-cost energy efficiency to all Northwest consumers.

Conversion to Electric Space Conditioning and Water Heating

Per the Power Plan analysis, jurisdictions pursuing economy-wide decarbonization goals should pursue multiple approaches to reduce carbon, including significant energy efficiency investment. While the Power Plan does not include electrification of end uses in its resource strategy, the Council recognizes that some jurisdictions may pursue electrification as part of a decarbonization strategy. Those jurisdictions (state or local governments) or utilities with such decarbonization goals that include electrification should take actions through codes, service standards, user fees or alternative programs, or a combination thereof, to achieve electric power savings from buildings. The efficiency level of new electric space conditioning or water heating equipment in these jurisdictions should be at least equivalent to the lowest-efficiency measure included in the 2021 Plan or adopted by the RTF (whichever is more recent). While some of the measures may not be cost-effective under the Council's current methodology, the Council believes they would be for jurisdictions with deep decarbonization initiatives. Similarly, for those jurisdictions, any existing inefficient electrical space or water heating equipment

28 www.commerce.wa.gov/growing-the-economy/energy/appliances

29 www.oregon.gov/energy/energy-oregon/Pages/Appliance-Standards.aspx

30 appliance-standards.org

should also be upgraded to a minimally efficient level at time of replacement.[31]

Surcharge Recommendation and Methodology

The Power Act authorizes the Council to recommend a surcharge that the Bonneville administrator may impose on customers that have not implemented conservation measures that achieve energy savings comparable to those that would be obtained under the Model Conservation Standards in the plan. Section 4(f)(2) of the Northwest Power Act directs the Council to include a surcharge methodology in the power plan. The surcharge must, per the Act, be no less than 10 percent and no more than 50 percent of the administrator's applicable rates for a customer's load or portion of load. The surcharge is to be applied to Bonneville customers for those portions of their regional loads that are within states or political subdivisions that have not, or on customers who have not, implemented conservation measures that achieve savings of electricity comparable to those that would be obtained under the model conservation standards.

The Council does not recommend a surcharge to the administrator under Section 4(f)(2) of the Act at this time. The Council intends to continue to track regional progress toward the plan's MCS and will review its decision on the surcharge recommendation, should accomplishment of these goals appear to be in jeopardy. Should utilities fail to enact these standards, then Bonneville may need the ability to recover the cost of securing those savings. In this instance the Council may wish to recommend that the administrator be granted the authority to place a surcharge on those utilities' rates to recover those costs.

The purpose of the surcharge is twofold: 1) to recover costs imposed on the region's electric system by failure to adopt the model conservation standards or achieve equivalent electricity savings; and 2) to provide a strong incentive to utilities and state and local jurisdictions to adopt and enforce the standards or comparable alternatives. The surcharge mechanism in the Act was intended to ensure that Bonneville's utility customers were not shielded from paying the full marginal cost of meeting load growth.

As stated above, the Council does not recommend that the administrator invoke the surcharge provisions of the Act at this time. However, the Act requires that the Council's plan set forth a methodology for surcharge

31 There may be cases where the savings are minimal relative to the expense (e.g., installing ductless heat pumps in small multifamily units) and may not be a priority efficiency investment. Jurisdictions will need to consider policy goals in determining what a reasonable cost-effectiveness limit should be.

calculation for Bonneville's administrator to follow.

Should the Council alter its current recommendation to authorize the Bonneville administrator to impose surcharges, the method for calculation is as follows:

Identification of Customers Subject to Surcharge

The administrator should identify those customers, states or political subdivisions that have failed to comply with the model conservation standards set forth within this chapter.

Calculation of Surcharge

The annual surcharge for non-complying customers or customers in non-complying jurisdictions is to be calculated by the Bonneville administrator as follows:

1. If the customer is purchasing firm power from Bonneville under a power sales contract and is not exchanging under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of all firm power purchased from Bonneville under the power sales contract for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.

2. If the customer is not purchasing firm power from Bonneville under a power sales contract but is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of the power purchased (or deemed to be purchased) from Bonneville in the exchange for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.

If the customer is purchasing firm power from Bonneville under a power sales contract and also is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is: a) 10 percent of the cost to the customer of firm power purchased under the power sales contract; plus b) 10 percent of the cost to the customer of power purchased from Bonneville in the exchange (or deemed to be purchased) multiplied by the fraction of the utility's exchange load originally served by the utility's own resources.

Evaluation of Alternatives and Electricity Savings

A method of determining the estimated electrical energy savings of an alternative conservation plan should be developed in consultation with the Council and included in Bonneville's policy to implement the surcharge.

Section 6: Resource Development Plan

How the Electric Sector Has Changed

The Council's 2021 Power Plan is significantly different than its Seventh Power Plan, adopted just five years ago. This is due to changes in the economics of renewable resources and the adoption of regional clean energy policies. The rapid cost reduction for solar and wind power technologies, when coupled with federal and state inducements, has provided an incentive for building large amounts of utility-scale solar and on-shore wind power across the region and put increased competitive pressure on thermal generators that operate at higher costs.[32]

Along with this changing economic landscape, the plan also recognizes clean-energy policies and goals implemented at state, city, and utility levels in many jurisdictions across the Western electricity interconnection and their impact on the future development of significant renewable and non-carbon emitting resources. The combination of increased competitive pressure and clean energy policies has resulted in the early retirement of less efficient thermal generators, and increased thermal generator planned retirements during the initial five-year "action period" of the plan. This indicates that the capacity of coal-fired power plants in the region will be reduced by more than 60 percent over the next decade.[33] Furthermore, uncertainty remains over the role of existing natural gas-fired power plants beyond this decade, and the future development of new gas-fired generators within the region.

Perhaps even more uncertain is the extent to which clean energy policies will affect other sectors of the economy and the demand for electricity. There is an increasing number of jurisdictions within the interconnection that have established policy goals and timelines to reduce greenhouse gas emissions economy-

32 To this point, the accelerated addition of renewable generators operating without fuel costs to the power supply has led to lower electricity prices, sometimes crossing below zero during intra-day trading.

33 Uncertainty regarding the future of existing coal plants in the region was apparent during preparation for the Seventh Power Plan, becoming a central issue for utility resource planning. Accordingly, the planned retirements of Centralia units 1 and 2, Boardman, and North Valmy units 1 and 2 between 2020 and 2026 were incorporated into the power plan.

wide, leading to potentially high levels of new demand. For example, in the transportation sector, the focus is on converting fossil fuel-fired vehicles to electricity or hydrogen. The widespread use of electric- and hydrogen-fueled vehicles would have a substantial impact on future electricity load growth. To this point, our early modeling work indicates significant electric system demand devoted to hydrogen fuel production for transportation – demand perhaps double the average output of the existing hydroelectric system. Combined, these actions signal a major paradigm shift for the electricity sector in the region (and elsewhere), presenting challenges to maintaining and enhancing an adequate, efficient, economical, and reliable power supply.

In the Seventh Power Plan, energy efficiency – the priority resource in the Northwest Power Act – was the clear, least-cost resource, with cost-effective energy efficiency acquisitions meeting most of the load growth through 2035. The region was undergoing a shift from a focus on energy needs to a focus on capacity - in particular peaking capacity - and ensuring an adequate system in poor water years or extreme weather conditions when the hydropower system has limited flexibility to meet peak needs. Deployment of demand response was also recommended to meet and reduce system capacity needs. Following energy efficiency and demand response, new natural gas-fired generation was the most cost-effective resource. The plants, and greater utilization of existing gas-fired plants, were part of the least-cost strategy to meet remaining resource needs and reduce carbon dioxide emissions from the electricity system. Finally, renewable resources were acquired near the end of the 20-year planning period to meet state renewable portfolio standards (RPS). Utilities were largely in compliance with near-term RPS targets due to earlier wind resource development, which saw the region build about 8 gigawatts in five years in the late 2000s and early 2010s.

For the 2021 Power Plan, the outlook is much different. There is less low-cost energy efficiency potential available due to the same price competition from solar and wind resources that now impacts thermal units, although the total cumulative potential at the end of the planning period remains the same. Ongoing construction of inexpensive renewable resources is influencing the wholesale electricity market, with low prices, particularly in the middle of the day, when solar PV is producing at its peak. In light of the construction of renewable resources anticipated in this plan, these low prices are likely to become increasingly negative through time, making it very difficult for resources with variable operating costs (like thermal plants) to commit and compete, leading to concerns about the adequacy and reliability of the system. The region's hydropower system – the biggest generating resource and "battery" in place – will also be facing long-term alterations in flow from climate change effects on weather and precipitation, as well as ongoing requirements to spill water to enhance fish passage. Water that is spilled cannot be used to generate power. These challenges are magnified when the hydropower system is increasingly used for flexibility and integrating new renewable resources.

In summary, the electric grid is shifting to renewable resources at an aggressive pace. This shift, along with the speed at which the system must react to demand for power, creates potential risks to system operations that we address in the plan. These changes also point to significant levels of low- or no-cost power available to the region during most daylight hours throughout the year. It is through the efficient management of these resources that the region will assure a reliable and economical power supply.

Recommended Resource Strategy

The Northwest Power Act requires the Council to prepare a regional conservation and electric power plan that assures the region an "adequate, efficient, economical, and reliable power supply." Since the first power plan in 1983, the Council considers a range of uncertainties and potential futures to determine its preferred resource strategy. The strategy balances analytical findings, policy expectations, and operational limitations within the grid. The resource strategy covers the entire plan horizon of 20-years (2022-2041) with a focus on a near-term, six-year action plan period (for this plan, the action plan period is 2022-2027).[34]

The resource strategy provides guidance to the entire Pacific Northwest region – encompassing both public and private utility territories - on how best to meet the electric power system needs. It is similar to integrated resource plans (IRPs) conducted by many utilities in the Northwest and around the country. Both consider supply- and demand-side resources as comparable means to meeting future needs and account for state policies that influence resource options. However, the Council's plan differs from IRPs in some important respects. By being a regional strategy, specific balancing authority or utility nuances are not necessarily captured. For example, the plan's strategy does not have specific requirements for additions to the transmission or distribution systems.[35] In addition, as a regional plan, there is less specificity on resource

34 The years represent water year, or October 1 – September 30.

35 *Section 10: Recommendations for Research and Development* includes a recommendation for the region to conduct a study on the ability of the transmission system to incorporate the proposed renewable power additions. The recommended resource strategy accounts for an estimated value of deferring transmission and distribution; however, utilities may have location-specific needs that are high-value that would have a costs and

acquisition recommendations than what may be provided in an IRP.

Regional Resource Recommendations

The 2021 Plan resource strategy includes recommendations on energy efficiency, generation, and demand response. Together, these will help support an adequate, efficient, economical, and reliable power supply while limiting greenhouse gas emissions. The recommendations for the Bonneville Power Administration, in part highlighted here, are specified in *Section 8: Recommendation for Amount of Power and Resources Bonneville Power Should Acquire to Meet or Reduce the Administrator's Obligation*.

The Council recommends Bonneville and the regional utilities plan to acquire between 750 and 1,000 average megawatts of cost-effective energy efficiency by the end of 2027 and a minimum of 2,400 average megawatts by 2041. This level of efficiency is cost-effective for meeting energy needs and is a low-risk approach to meeting adequacy needs (further described in *Section 9: Cost Effective Methodology for Providing Reserves*) by providing a hedge against reliance upon the availability of other resources at the time needed and supporting opportunities to unlock additional hydropower system flexibility. The addition of efficiency-based resources will also defer need for transmission and distribution system upgrades, reduce emissions, and support jurisdiction-specific decarbonization goals. In addition to the energy efficiency acquisition recommendation, *Section 5: Energy Conservation Program*, outlines other recommendations related to ensuring this efficiency is prudently acquired. Section 5 also provides the Model Conservation Standards and Surcharge Recommendation and Methodology, two required components of the plan.

Our recommendation is based on energy efficiency supply curves developed using estimated costs and savings data available through early 2020 for many different potential energy efficiency measures. We understand and expect the costs to acquire energy efficiency measures will vary between utilities and from one year to the next. This will likely alter the mix of efficiency measures available through utility programs in the region during the action-plan period. How much any particular utility invests in conservation, and which measures the utility invests in, are decisions for the utility to make based on a number of factors, including whether it makes economic sense to the utility in its particular circumstances. Given this reality, there will always be some

benefits that differ substantially from an estimated regional value. For more information see the supporting material at nwcouncil.org/2021powerplan_global-assumptions-power-plan. The analytics in the plan do not co-optimize individual utilities specific investment opportunities in generation, transmission, and distribution infrastructure. Regional utilities should consider the Council's recommendations within this context.

uncertainty of whether the amount of conservation that is cost-effective regionally will be acquired. Because of these factors, we believe it prudent to monitor progress in the acquisition of energy efficiency resources over the action plan period, including the cost to deliver such resources to customers. Further, we encourage greater collaboration between utilities to advance the overall effectiveness of energy efficiency resources.

For generation resources, the Council recommends the region acquire at least 3,500 megawatts of renewable resources by 2027, as a cost-effective option for meeting energy needs and reducing emissions. The Council also recommends that policymakers and utilities pursuing aggressive emissions reductions evaluate adding more renewables as a means of displacing emissions both within their portfolio and in the broader market. While these recommendations are part of the least-cost resource strategy, it is also important to note that we project there will be times that market conditions will result in substantial generation curtailment of both these new renewable resources and the existing renewable resources in the region. That is, there will be times when there is more electricity being produced than demand for electricity, and the region, as well as the broader West, will need to reduce the amount of generation on the system, in part by not using the total capability of renewables.

The plan evaluates broad regional trends but should not be seen to preclude more local and site-specific needs and opportunities. The Council acknowledges regional utilities will evaluate the suitability and efficacy of a broad range of resources, including resources not explicitly modeled as options in the power plan to meet those needs. Further, the Council acknowledges that all energy infrastructure development and construction – including new solar and wind plants and any potential new or upgraded transmission required to deliver that energy – has an impact on the environment. The Council recommends that the region be mindful of individual and cumulative impacts when siting new resources so that new renewable resource development is carried out in a manner that also protects the wildlife, fish, and cultural resources of the Pacific Northwest.

These resource additions will depend on sufficient transmission capability on the system to deliver electricity from the source of generation to the locations where electricity is needed. The Council understands that utilities with existing transmission rights should be compensated for the investments needed to construct large transmission projects. In our resource strategy, we do not identify what rights are available for adding renewable resources, but we understand regional utilities building these projects will need to use a variety of approaches to fit this expansion of renewable resource generation into the existing transmission system, respecting the rights of the transmission system owners and operators.

The Council recommends utilities examine two demand response products: residential time-of-use (TOU) rates[36] and demand voltage regulation (DVR) to offset the electric system needs during peaking and ramping periods and to reduce emissions. A given utility's time of need may differ from the region's, but these products are likely still part of a cost-effective strategy. Our assessment shows about 520 megawatts of DVR and 200 megawatts of TOU available by 2027.

With unique assets at each utility and across the region, the most strategically valuable program offerings may vary, so there may be other similar products that are also frequently deployable, low cost, and with minimal customer impact that could provide similar benefits; those should also be considered in utility planning. In addition to benefits on the power system side, demand response could be used to relieve transmission constraints and defer transmission and distribution system upgrades. The Council will track regional demand response implementation to assess progress, recognizing that the lack of a regionwide economic signal for capacity makes adopting demand response challenging. Based on the scenario analysis, the Council recommends Bonneville and regional utilities consider the value of adequacy, capacity, and emissions reduction when evaluating demand response in integrated resource plans and other analyses. As organizations and utilities develop demand response capability, they should do so by leveraging existing energy efficiency infrastructure and considering them together as part of an integrated demand-side management approach to optimize delivery of both resources holistically and equitably. We recognize, however, that our demand-response target recommendation depends, in part, on investments made by utilities to install advanced meters (AMI) across their service territories. While many utilities have installed advanced meters and the back-office architecture necessary to implement TOU rate designs, those that have not may need financial support to accomplish it. Therefore, we encourage Bonneville, regulators, and utility leadership to support investment in AMI architecture as a tool to encourage the most efficient use of grid resources.

36 The Council included both price (or tariff)-based and control-based products in the demand response supply curves. As a tariff-based product, TOU is not dispatchable and does not have a cash incentive for customers to participate and thus utilities have less ability to deploy for emergency needs. However, for a consistent, short-duration period of need, TOU can be beneficial. TOU was included in our demand response supply for analytical purposes, utilities may choose different analytical approaches in determining the value for their system.

In addition to these resources, the Council recommends Bonneville and the regional utilities, along with their associations and planning organizations, work together and with others in the Western electric grid to explore the potential costs and benefits of new market tools, such as capacity and reserves products, that contribute to system accessibility and efficiency. We would expect to see significant cost savings from greater regional collaboration to drive more efficiency into the system operations. A more aggressive examination would expand such a cost and benefit analysis to include the development of an organized or independently operated electricity market across the region. While any market design should protect the region's investments in its existing generation and transmission system, there may be reliability and cost benefits from the central dispatch of resources across a broad footprint. We also recommend the region concurrently work toward more collaborative understanding of the impacts of changes in market liquidity outside the region and the implications, especially for peaking and ramping periods, and pursue additional collaborative approaches to mitigate identified risks.

Historically, the Council has prepared a mid-term assessment of the plan a few years after its release and before work begins on the next plan. The primary purpose of the mid-term assessment is to check on the region's progress in implementing the plan.

The 2021 Northwest Power Plan includes many recommendations to the region and to Bonneville. We recognize that the regional power system is in an extraordinary time of change with many uncertainties associated with future system operations. The Council monitors the region closely and prepares annual adequacy assessments, forecasts, and other reports.

In the mid-term assessment for the 2021 Power Plan, we will update and examine its findings and examine any changes since it was finalized. While some circumstances will undoubtedly change after publication of the plan, we will examine if anything calls into question its fundamental strategy.

The Process of Developing the Recommended Resource Strategy

To make a recommendation to the region on how to meet the future needs for electricity most effectively, the Council assesses capabilities of the existing system and estimates the cost of adding new resources to keep up with system demands. The Council also needs to understand the costs of building and operating the system and how those costs change with different strategies to meet future energy needs. But both the system needs and the future cost of the system are uncertain. So, we project more than just an expected future need and associated costs; rather, we look at a wide range of potential system costs and needs.

This is done with a combination of computer-based mathematical models and analysis. The Council uses the Energy2020 model[37] to estimate the future need for energy. The output demand for electricity, which is part of the total energy need, is then carried into the AURORA model[38] that is used to estimate electricity prices and the GENESYS model[39] used to evaluate if the regional electric system can adequately meet the demand for electricity. We also use the output demand for electricity to formulate supply curves for energy efficiency and demand response. And we use the output of all these models and analyses in our capacity expansion model, the Regional Portfolio Model[40].

These models, used in conjunction with our staff expertise and consultation with regional experts, inform the Council's recommended resource strategy. All these models are made to explore a range of possible future conditions and outcomes. We cannot pinpoint the future the region will experience, but we can hope that by exploring how resource strategies perform under a wide range of potential future uncertainty, our recommendations will be adaptable and reduce the risks our region faces going forward.

Forecasts Used in Developing the Recommended Resource Strategy

To estimate the impacts of the recommended resource strategy, the Council forecasts elements that impact the cost, operation, environmental impact, and reliability of the regional electric system. Some elements that impact the cost of supplying electricity include the price for importing electricity from outside the region and the cost of fuel for power plants that operate inside the region. There are dozens of power plants operating in the region that consume fossil fuels like natural gas and coal; in particular, natural gas-fired generation has been growing. These fossil-fuel-based power plants become especially important to the region during low-water years when hydropower generation is limited. The price of fuel for these generating resources, or power plants, is a key determinant of the cost of the electricity they generate. This makes the fuel price forecast an important input for the power plan.

While these forecasts are directly tied to the cost of providing electricity, we also need to estimate how much electricity will be

37 www.energy2020.com

38 energyexemplar.com/solutions/aurora

39 nwcouncil.org/energy/energy-advisory-committees/system-analysis-advisory-committee/ genesys-–-generation-evaluation-system-model

40 nwcouncil.org/regional-portfolio-model

needed. The Council uses its 20-year demand forecast, which covers a range of future potential electricity needs, when developing the resource strategy.

The electric system is part of the broader regional use of energy, and increasingly there are technologies that can switch between using fossil fuels and electricity. One example of this is electric vehicles that use electricity to charge a battery rather than the traditional internal combustion engine vehicle that uses gasoline or diesel. Understanding the future need for electricity requires that the Council adopt a broader view of energy use in the region. This allows the Council to forecast how much of the demand for energy will be served by electricity and gain a holistic view of greenhouse gas emissions related to different energy choices in the region.

Electricity Price Forecast

To forecast the future electricity price, the Council must look at the broader Western electricity grid. How many and what types of power plants utilities and other power producers around the West operate, build, or retire impacts the price of electricity in our region. The ability or lack of ability to move electricity from where it's generated to where it's needed also impacts the price we pay for electricity.

There are many factors that impact what power plants are built in the Western electric grid – the cost of different generating technologies, state and federal legislation intended to limit greenhouse gas emissions, the services and support needed to maintain the balance of supply and demand for electricity, and the regulatory barriers to building new fossil-fuel-based power plants, are examples of the influences that affect where a facility is located and its technology.

Further, no power plant is built without available transmission to deliver its output to the utility network or location paying for the output. The Council looks at a variety of scenarios that have different compositions and magnitudes of the plants built to produce electricity. These are developed in consultation with regional experts to understand the factors that will influence electric utility decisions.

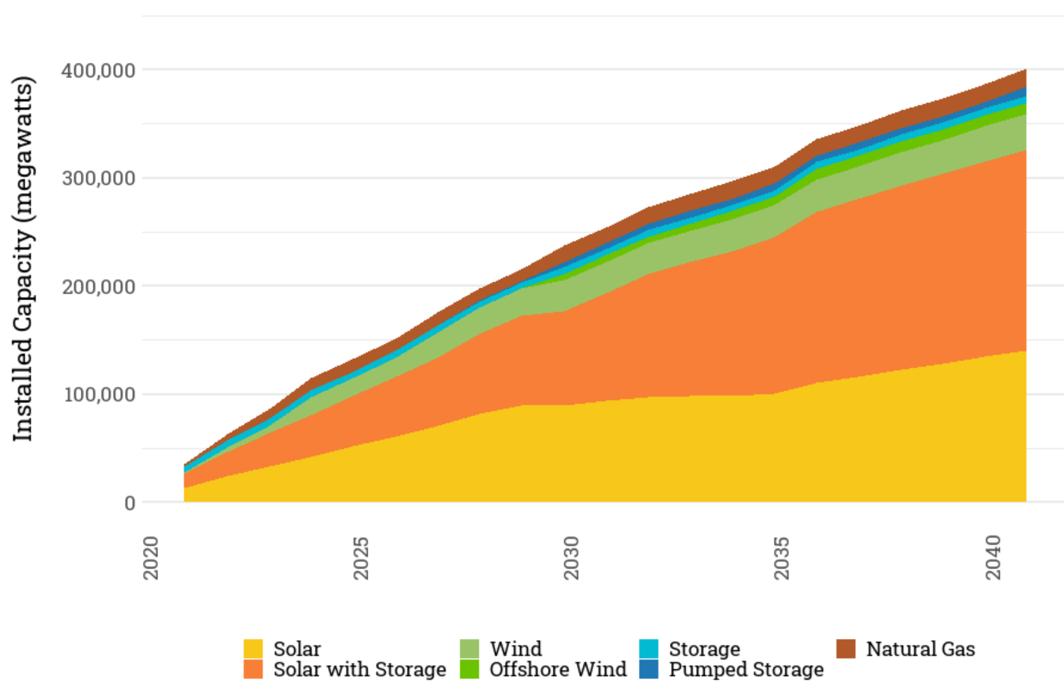
Considering the Council's' duty to assure an adequate and economically efficient supply of electricity for the region while respecting the renewable and clean energy targets of many Western states, the Council forecasts an extremely large addition of renewables. For example, the Council's baseline electricity price forecast adds around 400 gigawatts of nameplate capacity[41] to the Western electric

41 The nameplate capacity of a power plant is the maximum amount of electricity it can generate when it's fully functional and under optimal conditions or using the maximum amount of fuel. Another way of representing nameplate capacity is the manufacturer's rated output of the generator. Nameplate capacity should not be seen as representing the capacity contribution to system peak needs for any of the generating technologies

grid by 2041. The size of this addition meets the estimated reliability requirements for utilities outside the region and the states' requirements for renewable and clean power. It also limits the amount of new natural gas power plants to be built within region. To be clear, this forecast doesn't represent a forecast of power plants the Council expects will be built in the future. Rather, it shows what we estimate it would take to meet all the various requirements put on Western electric utilities.

However, such a large addition of new renewable power plants leads to a substantial oversupply of electricity during certain hours of the day and seasons in the year. The amount of electricity that could have been produced but instead is expected to be curtailed increases substantially through time with an addition of this magnitude. The next chart shows how the

Projected Generation Additions



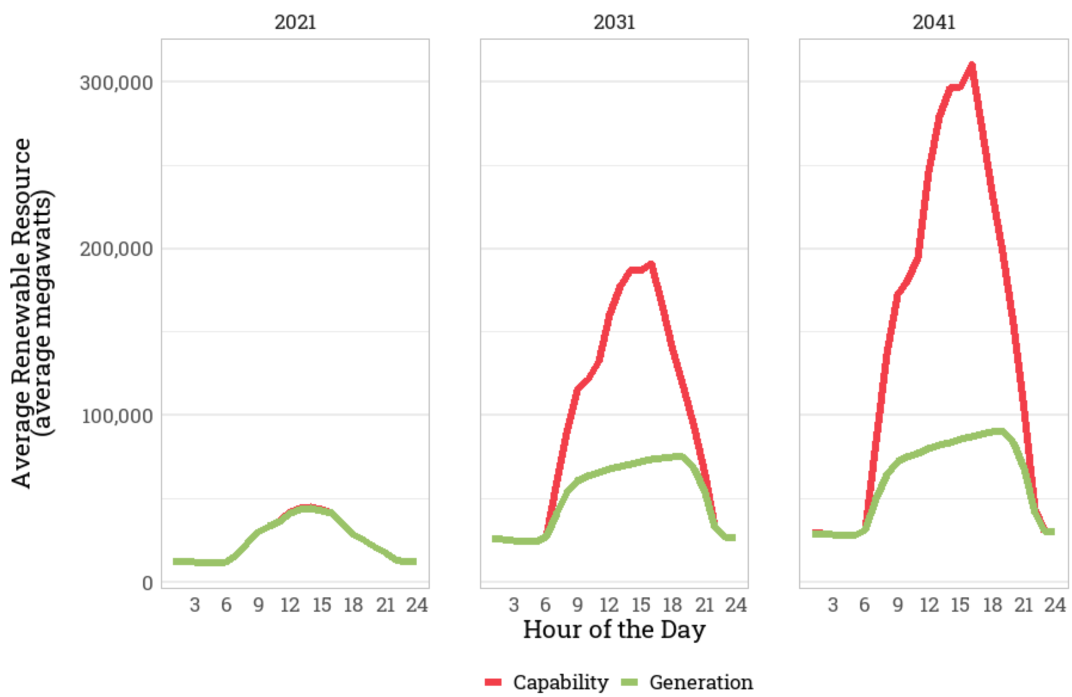
examined in this plan. For example, a wind plant with a 100-megawatt nameplate capacity will generate 100 megawatts when every turbine in the wind plant is at maximum output. However, during many hours when there is not enough wind, the wind plant will produce less electricity. Depending on location, a wind plant may average between 30 and 40 megawatts of generation over a whole year. In this case, the wind plant has between a 30- and 40-percent capacity factor. Further, neither nameplate capacity nor capacity factor should be confused with the capacity contribution to system peak needs, which is discussed in Section 4: Forecast of Regional Reserve and Reliability Requirements.

average amount of curtailed renewable generation increases substantially in 2031 and 2041 compared to 2021.

Regardless of how many power plants are built, the Council expects electricity prices to vary from year-to-year based on natural variability in demand for electricity and the available supply of electricity. In our region, electricity generated by hydropower is a substantial portion of the electricity we use. But the amount of electricity that can be produced depends on the weather. The weather can also drive demand for electricity, with extreme cold in winter or extreme heat in summer increasing the need for heating or air conditioning, requiring more electricity than normal.

From the River Management Joint Operating Committee (RMJOC) recent report on climate data analysis,[42] the Council selected three out of nineteen RMJOC climate scenarios to analyze the boundary conditions of potential regional climate change impacts.[43] From analysis of the temperature and streamflow data of the three RMJOC climate scenarios, the Council projects, in general, increasing winter hydropower generation due to increasing fall and winter streamflows from

Renewable Resources in the Western Electric Grid: Average Generation Versus Capability by Hour of the Day



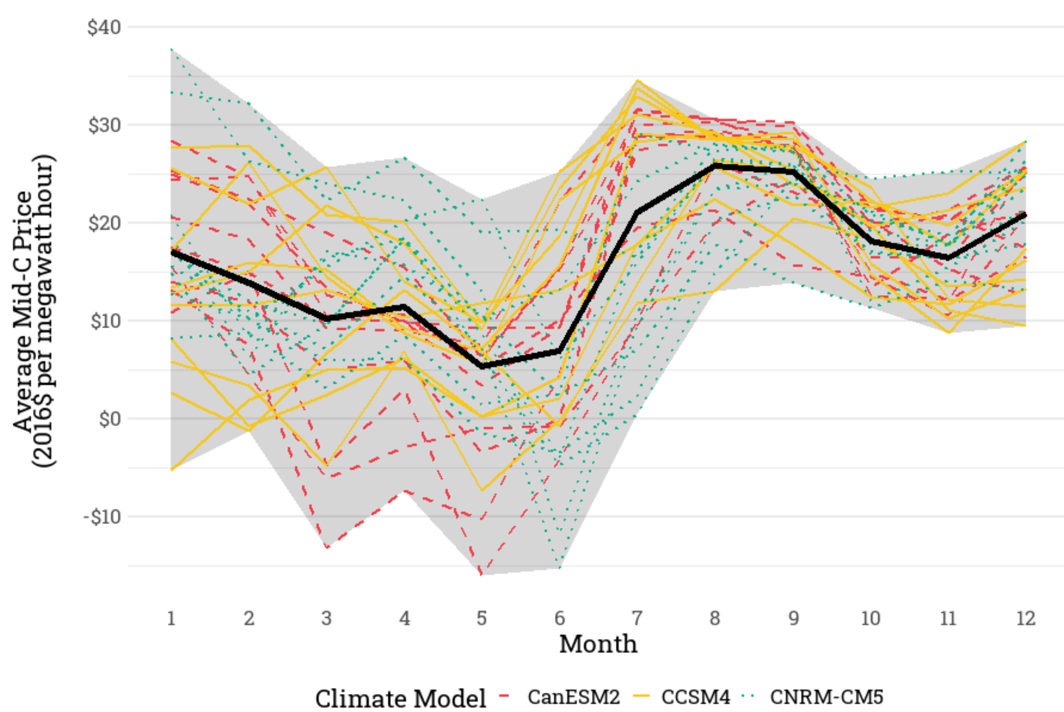
42 nwcouncil.org/2021powerplan_summary-climate-change-scenarios

43 nwcouncil.org/2021powerplan_climate-change-scenario-selection-process

having more precipitation which also falls as rain rather than snow, and in contrast, decreasing summer hydropower generation from decreasing summer streamflows caused by a shrinking snowpack and less summer precipitation.[44] Based on these data, the Council also forecasts, in general, a trend of less frequent extremely cold winter temperatures but more frequent extremely warm summer temperatures.[45] These climate impacts put downward pressure on winter electricity prices and align regional needs in the summer with the predominant electricity use in the Western electric grid. The Western electric grid uses more electricity in the summer than in the winter. All these factors taken together will put upward pressure on summer electricity prices.

The Council selected data for 30 different potential temperature and water conditions from the three climate scenarios for each year of the forecast horizon.[46] These data also include a decadal shift showing different anticipated conditions for the 2020s, 2030s, and 2040s. The changes from one decade

2026 Forecast Electricity Prices by Climate Model Hydro Conditions



44 nwcouncil.org/2021powerplan_trends-in-historical-and-climate-change-river-flows

45 Extremely cold regional winter temperatures are defined as those at or below 20F. Extremely warm regional summer temperatures are defined as those higher than 90F.

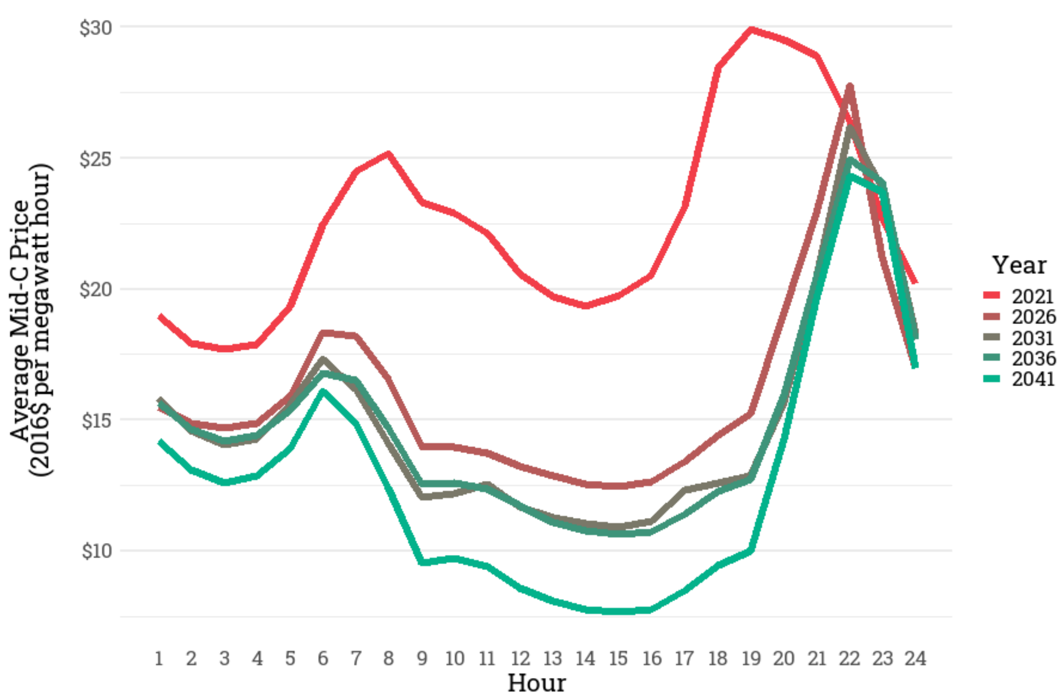
46 nwcouncil.org/2021powerplan_integrating-climate-change-policies-and-data

to the next reflect the continued impact of climate change.[47] Hydropower conditions with more water available for generating electricity cause lower electricity prices, whereas conditions with less water and thus less hydropower generation cause higher electricity prices.

Using the estimated range of electricity demand, the range of expected hydropower generation, and the range of expected wind and solar generation, the Council estimates electricity prices 20 years into the future. These prices help test the resource strategy under a wide range of potential electricity prices. In summary, the Council finds that:

- Timing and magnitude of wind and solar generation and how the generation aligns with electricity demand is a major driver of prices throughout the West
- Different amounts of water going through the hydropower system continue to be a major driver of seasonal price variation within the region
- At some level of building additional renewable generation, extremely low or

Mid-Columbia Average Hourly Prices



47 Specifically, the Council uses the Representative Concentration Pathway (RCP) 8.5 which reflects an end-of-century radiative forcing of 8.5 watts per square meter.

even negative prices occur, and these are aligned with times when we see substantial curtailment of renewable generation

- Prices for natural gas and coal continue to impact the electricity price during hours when fossil-fuel-based power plants are needed to preserve the balancing of the supply and demand for electricity

Altogether, this shows a downward trend for prices when looking at averages. Certain hours, especially during the evening, continue to show potential for higher prices, but prices during the middle of the day are driven down by an increasingly large amount of solar generation throughout the West.

Natural Gas Price Forecast

Generally, the price of fuel is a function of supply and demand. Factors that impact regional supply include how much gas can be extracted and processed, the capability to deliver natural gas to the region over pipelines, and how much gas is stored and ready to be delivered. The natural gas consumed in the Northwest originates from extraction fields in British Columbia, Alberta, and the U.S. Rockies. From there, high-pressure interstate pipelines move the natural gas into the region, where it is distributed to power plants, gas storage facilities, and homes, businesses, and industrial plants. Demand for gas typically peaks in the heating season, and if there are disruptions to supply, such as pipeline ruptures or equipment "freeze-offs," prices on the spot market can quickly escalate.

When this power plan was being developed, natural gas supply in North America was setting all-time high records through extraction techniques like hydraulic-fracturing and horizontal drilling. As might be expected, this resulted in low prices. In 2020, the average daily spot price for natural gas at the Sumas Hub on the Washington-Canadian border was $2.15 per MMBtu. Ten years ago, the price per MMBtu in current dollars was $4.60, and in 2005 it was $9.50. With the expectation of a sustained abundant supply and robust infrastructure, the Council forecasts continued low natural gas prices. However, as the region experienced in October 2018 with a pipeline rupture[48] in British Columbia, as well as the 2021 troubles in Texas,[49] natural gas prices can skyrocket on a daily or even monthly basis.

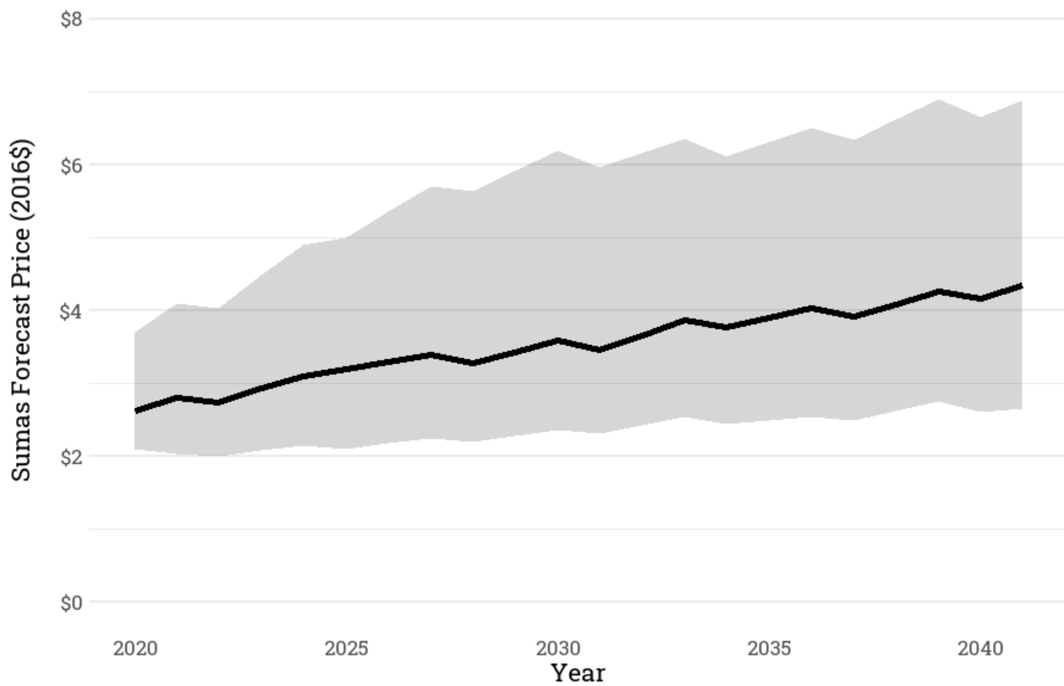
For the plan, the Council developed a range of prices across a suite of gas delivery points, including major gas hubs, power plant delivery points, and the city gate.[50] The figure

48 nwcouncil.org/news/gas-prices-spike-response-late-winter-cold-spell-and-pipeline-constraints

49 www.naturalgasintel.com/texas-investigating-natural-gas-pricing-during-february-winter-storm

50 City gate is the point where a natural gas local distribution company takes the gas off the pipeline system to distribute to customers. City gate prices are a common price point to look at for retail market prices.

Natural Gas Price Forecast for the Sumas Hub



above is the forecast of annual prices at the Sumas gas hub.

Coal Price Forecast

The price forecast for coal – which represents the delivered fuel price to each state from the Powder River Basin in Wyoming – is relatively flat and stable. Wyoming is the largest coal-producing state in the United States and a single mine – the North Antelope Rochelle/Peabody Mine – supplies 13 percent of the coal in the country.

Forecast of Delivered Coal Price in 2016 $/MMBtu

State	2020	2025	2030	2035	2040	2045
Montana	$1.37	$1.46	$1.51	$1.52	$1.55	$1.56
Oregon	$2.19	$2.33	$2.41	$2.43	$2.45	$2.46
Washington	$1.91	$1.90	$1.89	$1.91	$1.93	$1.94

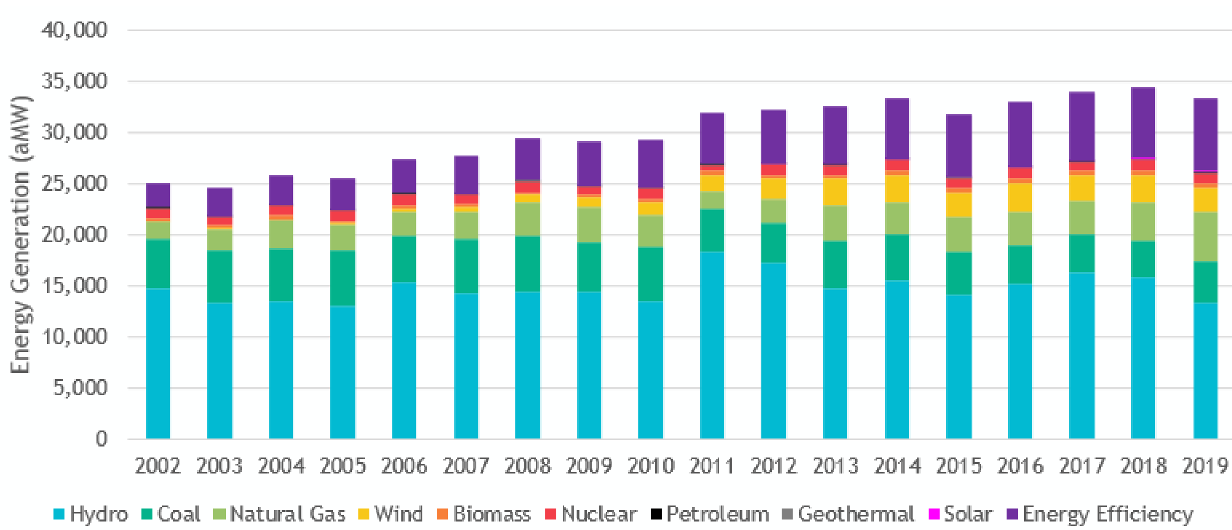
Assessing the Capabilities of the Existing Regional Electric System

The Pacific Northwest power system is undergoing a major shift that will alter the current energy supply landscape over the next several decades. New state and local policies are affecting existing resource dispatch and future resource development. Coal-fired generators are being phased out due to economics and initiatives to reduce greenhouse gas emissions. The future of natural gas development and contributions to the system are uncertain. Inexpensive wind and solar development continue to dominate new construction. Energy storage is becoming more common in the West, both as a stand-alone resource technology and partner to renewables, with the cost for the technology declining substantially in the last few years.

Resources

There are about 63,000 megawatts[51] of generating resource capacity either installed in the Pacific Northwest or located just outside the region and under contract. In addition, some of these megawatts installed in the region are also serving load outside of the region, such as wind projects under long-term power purchase agreements to California and surplus supply exported outside the region through the electricity markets. On average, the region's resource portfolio generates about 26,000[52] average megawatts annually. When energy efficiency

Pacific Northwest Annual Energy Production, including Energy Efficiency



51 See nwcouncil.org/news/megawatt-powerful-question

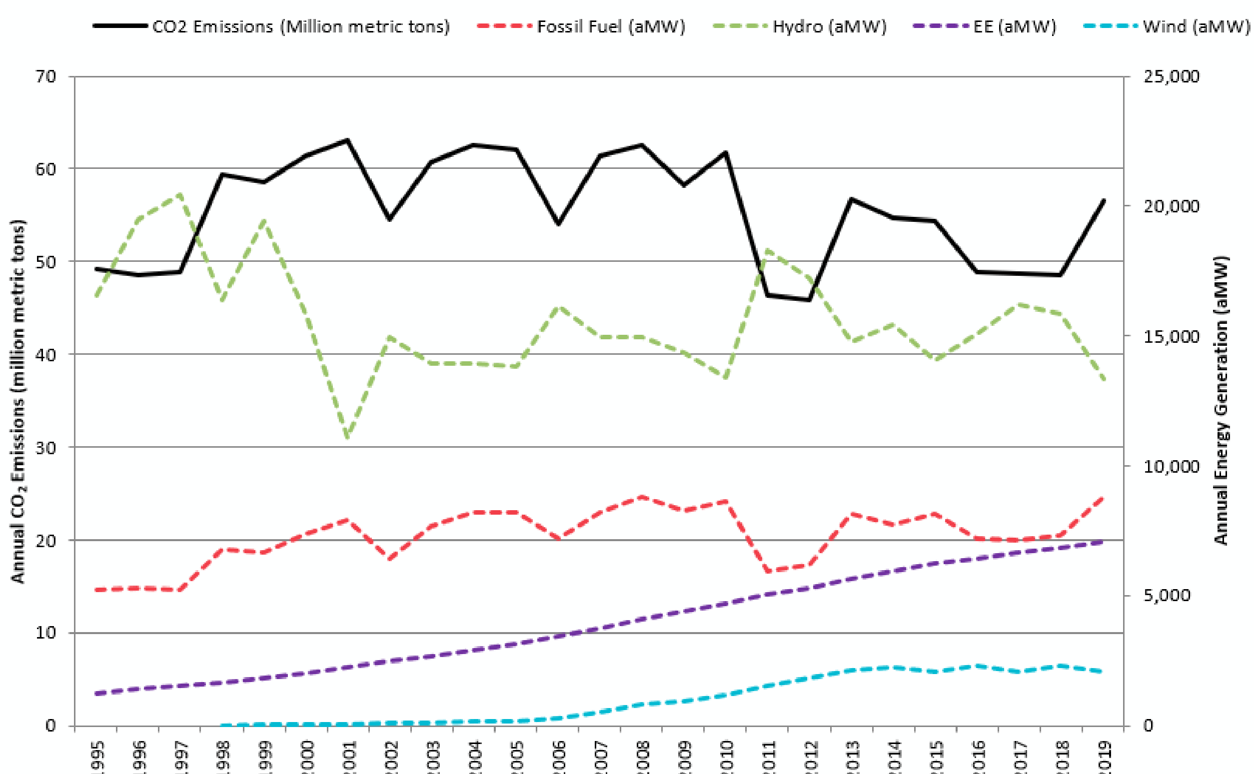
52 From 2012 to 2018 the total generation in the Western electric grid was about 99,131 average megawatts so the region is about a quarter of the total load.

is included, that number increases to about 32,500 average megawatts.

Hydropower generation remains the cornerstone of the Pacific Northwest power system, dominating the regional energy supply. However, hydropower generation varies significantly from year-to-year, depending on weather conditions and snowpack levels. The regional dispatch of fossil fuel resources is directly related to how much electricity is produced with hydropower. In years with lots of water flowing through the hydropower system (for example, 2011), coal and natural gas resources generate less electricity, whereas in years with less water (for example, 2019) they generate more.

The Pacific Northwest has one nuclear plant – Columbia Generating Station – that produces consistent and predictable generation, following a biennial springtime refueling schedule. Onshore wind has made an increasing annual contribution to the region's energy supply, as wind development picked up in the mid-2000s in response to state renewable portfolio standards and federal tax incentives. Solar photovoltaics (PV) began to appear in the region in 2010, and while

Direct Carbon Emissions (left y-axis) from the Generation of Electricity Compared to Amount of Generation by Fuel (right y-axis)



the current solar PV fleet is relatively small compared to other resources, it is expected to increase because the cost of solar has declined so significantly. Rounding out the region's energy generating portfolio are biomass resources, geothermal, and standby petroleum plants.

In addition to generating resources, demand side management resources play a significant role in the region. Energy efficiency is the region's second largest resource. Since 1978, the region has achieved more than 7,000 average megawatts of efficiency savings – around three times the average output of the Grand Coulee Dam, the region's largest generating plant.

Over the past 25 years, annual carbon emissions from the generation of electricity have averaged 55.5 million metric tons of carbon dioxide (not including upstream emissions). The relationship between hydropower generation and fossil fuel dispatch leads to the region's carbon dioxide emissions varying from year-to-year. This can make it difficult to decipher overall trends, although there are indications that demonstrate emissions have been decreasing overall – and that is because of fossil fuel generation dispatch. While fossil fuel generation largely dispatches based on hydropower conditions, overall, fossil fuel generation has been steadily increasing. However, the dynamic between coal and natural gas dispatch is changing. On average, coal generation has been slowly declining in the past few years due to coal plant economics and low natural gas prices. Conversely, natural gas dispatch has been increasing thanks to low fuel prices and increased natural gas availability. In 2018, natural gas generation surpassed coal generation on an annual basis for the first time. As coal units in the region are scheduled to retire, and as energy efficiency, wind, and solar continue to increase, emissions will begin to noticeably decline on a consistent basis.

Upstream Methane Emissions

Natural gas has been undercutting coal economically for some time, and the combustion of gas emits less carbon dioxide (CO_2) than coal. However, the primary component of natural gas is methane (CH_4); a greenhouse gas that when released directly into the atmosphere has a warming potential over 80 times[53] that of CO_2 over 20 years.

There are two primary greenhouse gases related to the combustion of natural gas – CO_2, and CH_4. Direct emissions refer primarily to the CO_2 emissions released at the point of use. Upstream emissions occur as methane is released or accidently leaked to the atmosphere as fossil natural gas is extracted and transported to the point of use.

53 www.epa.gov/ghgemissions/understanding-global-warming-potentials

The global atmospheric concentration level of methane has been steadily growing since NOAA[54] began taking measurements in 1983. Some of the largest annual increases have occurred in recent years, indicating the problem is getting worse. It's not clear what all the causes are, but oil and natural gas activities contribute to the overall global methane emissions. By estimating upstream methane emissions related to fossil fuel use in the region, the Council gets a more accurate picture of greenhouse gas emissions related to regional energy use. With an increased focus on the upstream methane release issue, the Council expects there will be fewer releases in the future.

Policies

The adoption of state renewable portfolio standards (RPS) in Washington, Oregon, and Montana[55] in the mid-2000s, combined with federal and state tax incentives and renewed opportunities for PURPA-qualifying facilities, contributed to a significant increase in renewable resource development over the last two decades. Now, as tax incentives phase out and upcoming RPS targets are on track for compliance, a new policy movement is developing – decarbonization of the electricity system. States, utilities, and communities have instituted aggressive clean-energy targets and economywide greenhouse gas reduction goals that will influence the future construction of generating plants in the region, Western electric grid, and national electric system. In the Northwest, Washington and Oregon have statewide clean-energy regulations, requiring a 100-percent clean, non-emitting electricity supply by 2045 and 2040, respectively. Idaho and Montana also have state greenhouse gas reduction goals, and utility- and community-level clean electricity goals that, in addition to a state RPS, lead to considerable aggregate state clean-energy goals.

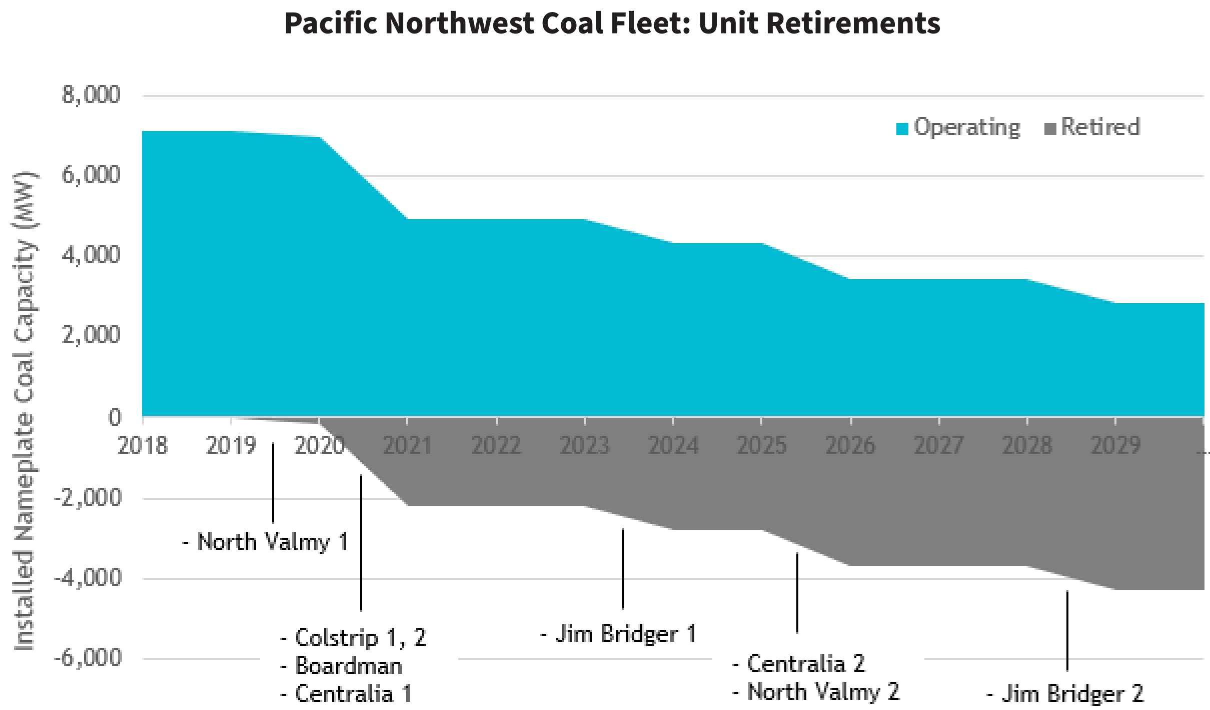
Retirements

With the increasing emphasis on decarbonization, specific policies that prohibit coal-fired generation in the future have been enacted in several states in the West – including Oregon and Washington. In addition, the economics that previously favored inexpensive coal-fired generation have dramatically swung to favor natural gas generation due to consistently low natural gas prices and low-cost renewable resources that have low or no variable operating costs. This has led to the early closure of coal-fired generators in the region and across the West.

In 2018, the region's coal fleet totaled around 7,000 megawatts of capacity. In just a few short years, with the retirement of Colstrip units 1 and 2, Boardman, Centralia unit 1, and Idaho Power's exit from North Valmy unit 1, the coal fleet is now just under 5,000

54 gml.noaa.gov/aggi/aggi.html

55 Montana repealed its RPS in May 2021



megawatts. By the end of 2028, that number will decrease even more to around 2,400 megawatts through the planned retirements of Jim Bridger units 1 and 2, Centralia 2, and North Valmy unit 2. While some coal units remain in 2029, with multiple owners and competing interests for each remaining unit, the future of these resources is uncertain.

Assessing the Potential for New Resources

In assessing the potential for new electricity resources, the Council considers not only the cost of maintaining and fueling the existing electric system, but also the cost of adding new resources to meet changing and expanding needs for electricity in the region. The Council estimates the cost and potential for resources that the region can use to meet these needs. This helps in getting a complete picture of the cost of supplying the region's future electricity needs. In developing a resource strategy, the Council analyzes the difference in cost and performance of potential additional resources to make recommendations for the most effective way to adequately meet regional demands for electricity.

New Opportunities for Energy Efficiency

Energy efficiency is a reduction in the use of electric energy from the increased efficiency of energy use, production, or distribution. Historically it has been the least cost resource acquired by energy providers. As such, energy efficiency acquisition reduces system costs and is specifically referenced in the Act as the priority resource to be selected by the plan before renewables, natural gas plants, and other generators are considered. Energy efficiency has helped the region avoid the need for, and the costs associated with, building and maintaining numerous power plants, as well as the price risk associated with fuel purchases needed for thermal plant operations. In addition, energy efficiency supports system reliability and hydro system flexibility, and it has been used to avoid or delay distribution system investment to serve peak load. For these reasons, assessing the potential for energy efficiency to meet future system needs is an essential part of the plan. The Council assesses all efficiency completed through utility programs, energy codes, appliance standards, and natural market impacts prior to the start of the plan. These are included as part of the demand forecast and not included in the forward-looking energy efficiency potential estimates.[56]

The starting point for assessing the potential for energy efficiency as a resource is to define each unit of savings, or "measure." A few examples of these measures[57] include efficient light bulbs, insulation, better windows, heat pump water heaters, and more efficient fans. The energy savings per unit (e.g., electricity consumption of a heat pump water heater relative to a standard electric resistance unit), combined with the number of units (e.g., number of homes with electric water heating) provides the amount of savings potential for a given measure. Adding up all the possible measures for homes, businesses, and industries results in a forecast of efficiency potential.

In addition to the electricity savings, a measure is defined by the incremental cost to install or implement the efficiency and a variety of other costs (e.g., maintenance cost) or benefits (e.g., additional water savings). The Council takes all the costs and benefits and adjusts the total cost[58] of these measures to come up with a cost that can be compared to other types of resources.

The amount of energy efficiency available during the planning horizon is developed and formulated into a supply curve, which gives the amount in average megawatts of savings at different measure costs (in dollars per megawatt-hour). The energy efficiency supply curve below shows all energy efficiency

56 Energy building codes and appliance efficiency standards established prior to the end of 2019 are accounted for in the Council's baseline forecast.

57 To define the individual measure costs and savings, several sources are used. Primary among them is the Regional Technical Forum (RTF). For measures not considered by the RTF, the Council relies on secondary studies from both regional (e.g., NEEA) and national sources (e.g., DOE). The total number of units (e.g., number of homes) in the region is largely based on the sector-specific stock assessments conducted by NEEA.

58 The measure costs include total system cost (per the Northwest Power Act), and both costs and benefits combined into a net levelized cost, referred to as the Northwest Resource Cost. This levelized cost is the net present value of the measure costs divided by the measure savings. In this manner, the costs for conservation are developed consistently with other generating resources.

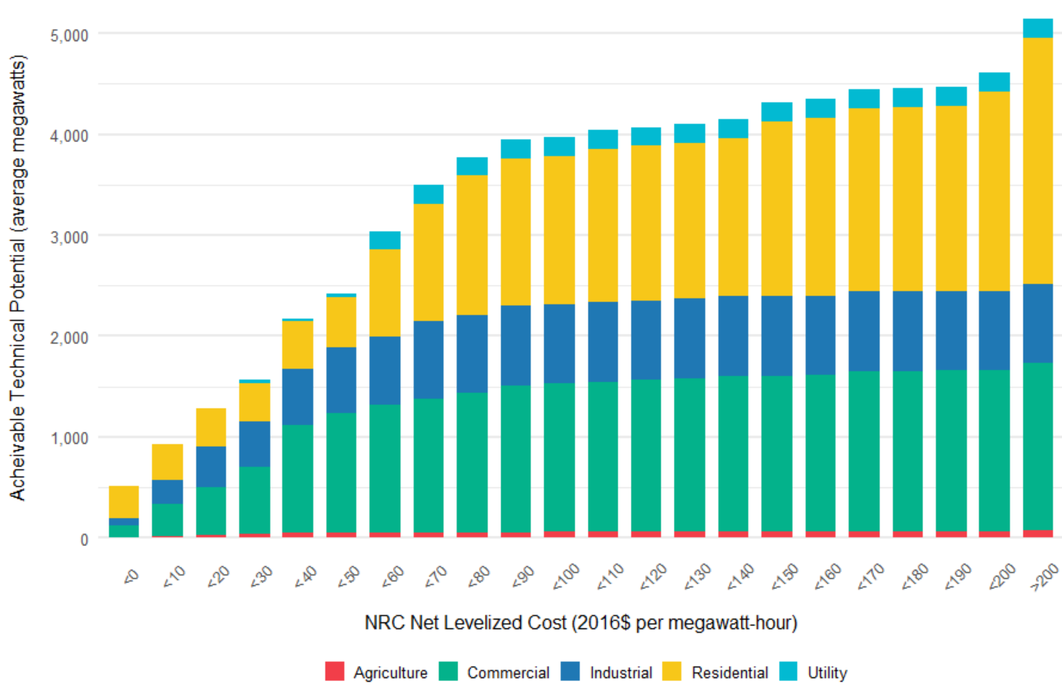
available through 2041, differentiated by sector and by cost. The figure shows 1,337 average megawatts as the total amount of energy efficiency potential by 2027 and 5,144 average megawatts by 2041, accounting for technical and feasibility limitations. The supply curve is used to compare energy efficiency to other electricity resources, providing an amount of efficiency available at increasing costs, and can be used to meet future regional electric system needs.

The timing of when the savings from energy efficiency occur is also an important part of our analysis. As the price of electricity varies by day and by season, the value of the energy efficiency will also vary, depending on the timing of savings. For the supply curves, energy savings are greater during winter than summer. The shape of the savings for the complete set of energy efficiency is developed by combining all the individual measure shapes.

Demand Response Supply Curve

Demand response (DR) is "*a non-persistent intentional change in net electricity usage by end-use customers from normal consumptive patterns in response to a request on behalf of, or by, a power and/or distribution/ transmission system operator. This change is driven by an agreement, potentially financial, or tariff between two or more participating*

Energy Efficiency Supply Curve, Differentiated by Sector for 2041



parties.”[59] The need for demand response arises from the mismatch between power system costs and consumers’ prices. While power system costs vary widely from hour to hour as demand and supply circumstances change, consumers generally see prices that change very little in the short term. The result of this mismatch is that consumers do not have the information that might encourage them to curb consumption at high-cost times and/or shift consumption to low-cost times. The ultimate result of the mismatch of costs and prices is that the increased power system needs require building more peaking capacity, building more transmission, and incurring more system upgrades than would be necessary if customers changed their use in response to price changes in the market. Programs and policies to encourage demand response are efforts to provide this information to consumers and create the infrastructure to allow them to respond to price signals in the market.

The Council evaluated demand response products that impact residential, industrial, commercial, and agricultural sectors, as well as the utility distribution system. Demand response products evaluated include utility-controllable and price-responsive options across the sectors. Utility-controllable products give the utility the ability to change the operation of end-use equipment to reduce peak. Price-responsive products give the end-use customer the ability to choose how to modify loads based on a price signal from the utility. In general, price-responsive products are less expensive because equipment needs are lower, but the utility has less control over the resulting impact.

In total, 23 demand response products were incorporated into demand response supply curves. The Council estimates about 3,721 megawatts of summer load reduction potential and 2,761 megawatts of winter load reduction potential.[60] This potential was focused on reducing load during times of system need, though it is recognized that demand response could also be used to increase loads during low or negative prices to balance with supply. The potential is based on an estimated impact per participant and the potential number of participants based on eligibility (e.g., customers need to have air conditioning to participate in an air conditioning control program); assumptions of willingness to participate; and participation rates for any given demand

59 This definition was developed by the Demand Response Advisory Committee nwcouncil.org/energy/energy-advisory-committees/demand-response-advisory-committee

60 The difference in load reduction is based on the underlying demand response measures. Some programs, like curtailment of residential air conditioning only impact the summer season, while other programs like space heating only impact the winter season. While the potential numbers referenced here give a sense of the impact of demand response relative to other resources, the deployment of demand response by utilities could differ based on needs.

response event (a customer may opt out of any given event).

Products range in cost from $5 per kilowatt-year up to $250 per kilowatt-year (2016 dollars). These costs include setup, operation and maintenance, equipment, marketing, and incentives. The Council also incorporates benefits (or negative costs), such as deferring buildout of the transmission and distribution system by reducing electricity use during times of the highest electricity need.

New Generating Resources Potential

New generating resource technologies are assessed based on their cost, operating, and performance characteristics, and developable potential in the region. Resources that are commercially available and proven and have the potential to meet future needs in the region are further developed into reference plant estimates representative for the Pacific Northwest – with a designated plant size and configuration, performance attributes, costs, and other attributes such as construction schedule and economic life.

The Council developed reference plants for utility-scale solar photovoltaics (PV), solar PV + battery storage, stand-alone battery storage, onshore wind, natural gas combined cycle turbines, natural gas peakers, and pumped storage. In addition, one emerging technology reference plant was developed as a proxy for the many promising new technologies (for example, offshore wind, small modular nuclear, and enhanced geothermal systems) that could provide value to the region in the future.

The costs of renewable resources – and in particular solar PV – have decreased significantly.[61] Despite recent price fluctuations due to tariffs on imported materials and cells, the cost of solar PV is expected to further decrease in the future. While the cost of natural gas combined-cycle plants has largely remained the same, the cost of a natural gas frame unit – operated in simple cycle mode as a gas peaker – has decreased due to lower equipment costs and greater competition among vendors to secure fewer project development contracts. The costs of conventional geothermal and pumped storage hydropower resources are extremely site-specific, so it can be difficult to see any major trends.

61 According to the Lawrence Berkeley National Lab, over the past decade the installed cost of solar has declined about 70 percent and the installed cost of wind has declined about 40 percent. (emp.lbl.gov/webinar/utility-scale-wind-and-solar-us)

New Generating Resource Reference Plants: Capital Cost (2016$/kW) Trends

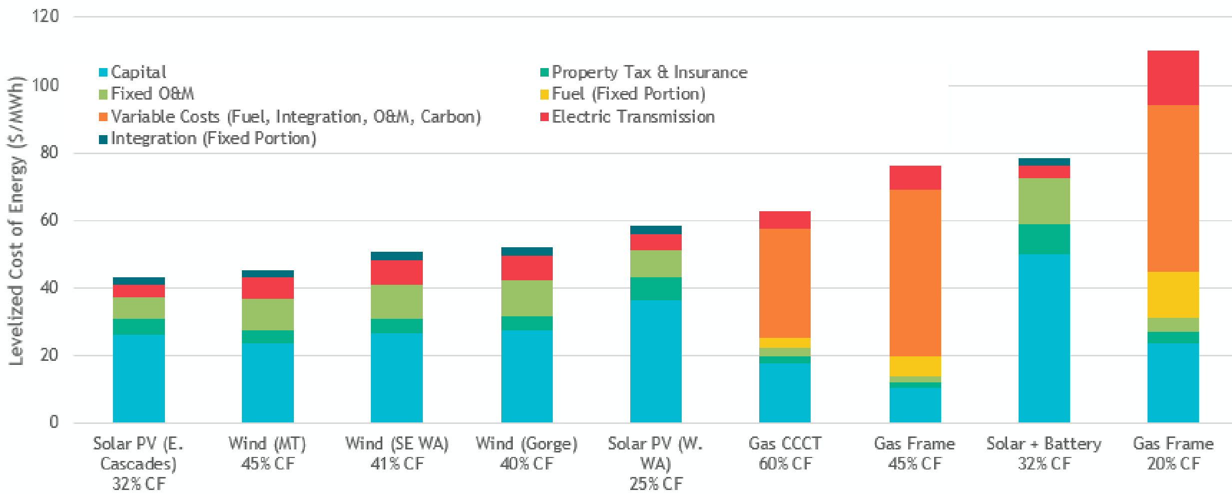
Resource	Seventh Plan (2016$/kW)	2021 Plan (2016$/kW)	Trend
Onshore Wind	$2,382	$1,450	Significant decrease
Solar PV	$2,566; $1,792 (low cost)[62]	$1,350 (E. Cascades); $1,465 (W. WA)	Significant decrease
Solar PV + Battery Storage (4 hr)	–	$2,568	–
Battery Storage (4hr)	–	$1,400	–
Pumped Storage	–	$2,300	–
Geothermal	$4,575	$5,400	No significant change
Natural Gas - Combined Cycle Combustion Turbine	$1,220	$1,150	No significant change
Natural Gas – Peaker (Frame)[63]	$859	$550	Decrease
Proxy Emerging Tech – Small Modular Reactor	–	$5,400	–

One way to compare the cost of a resource against another is to look at the levelized cost of energy, which is a metric used to estimate the cost of energy across a resource's expected economic life. It is calculated as the cost per unit of energy a resource is expected to generate (under an assumed level of dispatch or capacity factor) that also includes variable costs such as fuel. Although the initial cost for solar and wind may be higher than gas resources, with minimal operating costs (no fuel purchases), the overall cost of producing energy can be significantly less.

62 When the Council was evaluating solar PV in 2015 for the Seventh Power Plan, costs were dropping so quickly that a lower-cost solar PV resource option was added to the model analyses.

63 This price decrease also reflects a change in the reference plant technology class

New Generating Resource Reference Plants: Levelized Cost of Energy ($/MWh)[64]



While the Council doesn't explicitly model all new resource options, there are other commercially available resources with smaller-scale, location-specific potential in the Pacific Northwest (for example, biomass, small hydropower, distributed generation) that if cost-effective should be considered viable resource options for future power planning.

Planning for an Uncertain Future

The electric sector is in a time of transition. A wave of coal unit retirements will happen over the next decade. Climate change is altering hydropower generation, and policies designed to limit greenhouse gas emissions constrain how the electric sector expands the supply of electricity.

Utilities and regulators are looking to replace coal with completely different generating technologies like wind and solar generation. The cost of building solar and solar with on-site batteries has fallen substantially. But relying more on new technologies requires changing how the electric grid operates. The expansion of the Western Energy Imbalance Market makes the operation of the Western electricity grid more automated and intertwined. But it's just a start on the scope of change needed to transform the way electricity is generated.

The future of Northwest utilities will be different than the past.

64 In this graph, CF denotes capacity factor. For each generator, the capacity factor indicated the average amount of energy over a year relative to the installed capacity that was used in the levelized cost calculations for comparison.

Exploring Key Power Supply Questions Through Scenario Analysis

Understanding the potential future risk that will impact the electric sector of the economy takes a broad range of analyses. Some analyses involve creating a range for potential risks. For example, the Council forecasts a range of natural gas prices. The Council uses analytical approaches to consider the implications of natural gas prices that deviate from our expectation.

Other risk analyses involve setting up scenarios, or a set of high-level questions, that help assess future alternatives. The Council builds these scenarios by asking what conditions and processes would change and then reflecting them in our analytics.

Ultimately, scenario analyses help inform decisionmaking when developing the recommended resource strategy for the region and for Bonneville.

How the Scenarios Were Selected

The Council looked at high-level themes in the electric sector and the Northwest Power Act in constructing the scenario analyses. To incorporate Power Act requirements, the Council first focused on analyses that examined the adequacy of generating resources to meet the regional needs. Given the expansion of the Energy Imbalance Market in the West since the last power plan, the Council saw changing and expanding markets for electricity as an important theme for this plan.

The Council also used analyses to distinguish between the impacts of a resource strategy on Bonneville's portfolio of resources and the demand for electricity Bonneville is obligated to serve with those resources. Finally, the Council expected that understanding the implications for greenhouse gas emissions for the region was an important part of looking at future strategies on how the region can meet the demand for electricity.

After identifying these high-level themes, the Council examined seven scenarios to guide the analyses. The scenarios connected to one or more of the high-level themes and created distinct narratives that the Council determined would help construct an overarching resource strategy.

How the Scenarios Were Constructed

To construct the scenarios, the Council developed models and analyses that would be part of this plan. The Council then identified, given the narrative for each scenario, where the models and analyses had parameters that would differ. Each scenario involved exploring a range of different values and combinations for these parameters.

Scenarios Explored

The Council explored a range of scenarios designed to answer key questions about the future of the electricity grid. These scenarios echo previous Council plans and also break new ground. The scenarios are:

Change in Reliance on Extra-Regional Markets for Resource Adequacy – an analysis of the impacts of relying on markets outside the region for resource adequacy.

Organized and Limited Markets for Energy and Capacity – an analysis of potential impacts from changing the structure and reliability of markets outside the region.

Early Retirement of Coal Generation – an analysis of the implication of accelerating planned retirement dates for coal generation throughout the Western electricity grid.

Robustness of Energy Efficiency – an analysis of how the resource strategy would change with different estimates and assumptions regarding the supply of energy efficiency.

Analyze the Bonneville Portfolio – an analysis of the Bonneville administrator's obligation to provide electricity and the available federal resources dedicated to meeting that obligation.

Greenhouse Gas Regulation and Cost Impacts – an analysis of the impacts of limitations, financial or otherwise, on greenhouse gas emissions from the electricity sector.

Pathways to Decarbonization – an analysis of the impact on the electricity sector of efforts to substantially reduce economywide greenhouse gas emissions.

Findings From Our Scenario Analyses

The Council has different methods for accounting for uncertainty. While some uncertainty or risk is modeled using ranges of values, for example the range of future electricity prices, some uncertainty does not lend itself to using a range of values. For those types of uncertainty, the Council uses scenario analysis. While scenario analysis is a useful method to describe uncertainty, it often looks at very unlikely outcomes to help in understanding the direction that policies or goals lead. The following descriptions of our scenario analyses focus on what we learned from these exercises. They should not be taken as a forecast of what is likely or as the sole basis for how we formulate a resource strategy.

Change in Reliance on Extra-Regional Markets for Resource Adequacy

The Northwest spent billions building transmission to connect to the rest of the West. This enables surplus electricity sales that offset the regional cost of electricity and allows purchases when the regional need exceeds the capacity of regional generators. Relying on electricity purchases from outside the region defers the need to build new generators, which reduces the cost of using electricity. However, maintaining reliable electricity requires both transmission to the Northwest and available generators outside the region.

Our baseline setup limits the amount of imports from the external market. After accounting for imports from power plants that are located outside the region but have contracts or obligations to deliver electricity to the region, the analysis limits regional imports to no more than 2,500 megawatts in the winter and 1,250 megawatts in the summer. Those limits are well below the ability of the region to import electricity on our transmission system. Because the Council has less information on the supply and demand for electricity outside the region, the Council uses these limits to represent uncertainty about the availability of electricity during times when the region is short of generation and fuel.

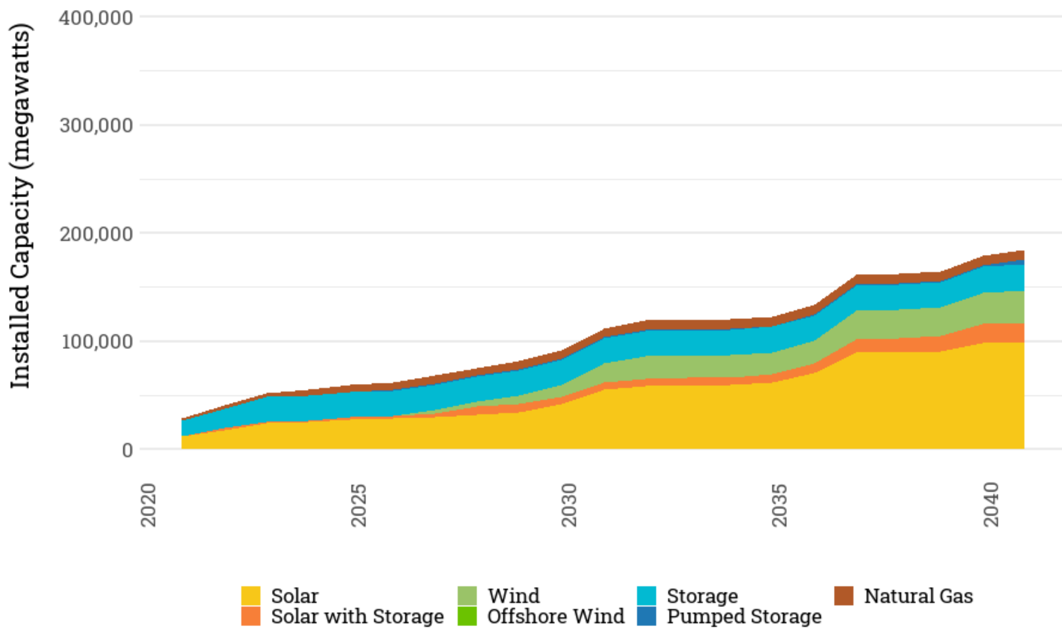
For this scenario, the Council relaxed these limits to allow the region to import up to the capability of the transmission system. While this reduced the adequacy-needs input into our resource analysis, the results from our models had minimal changes to the resource additions examined. While there were some minor changes to the pace at which renewable generators are built within the region, the overall results did not indicate removing these limitations would change the resource strategy.

Organized and Limited Markets for Energy and Capacity

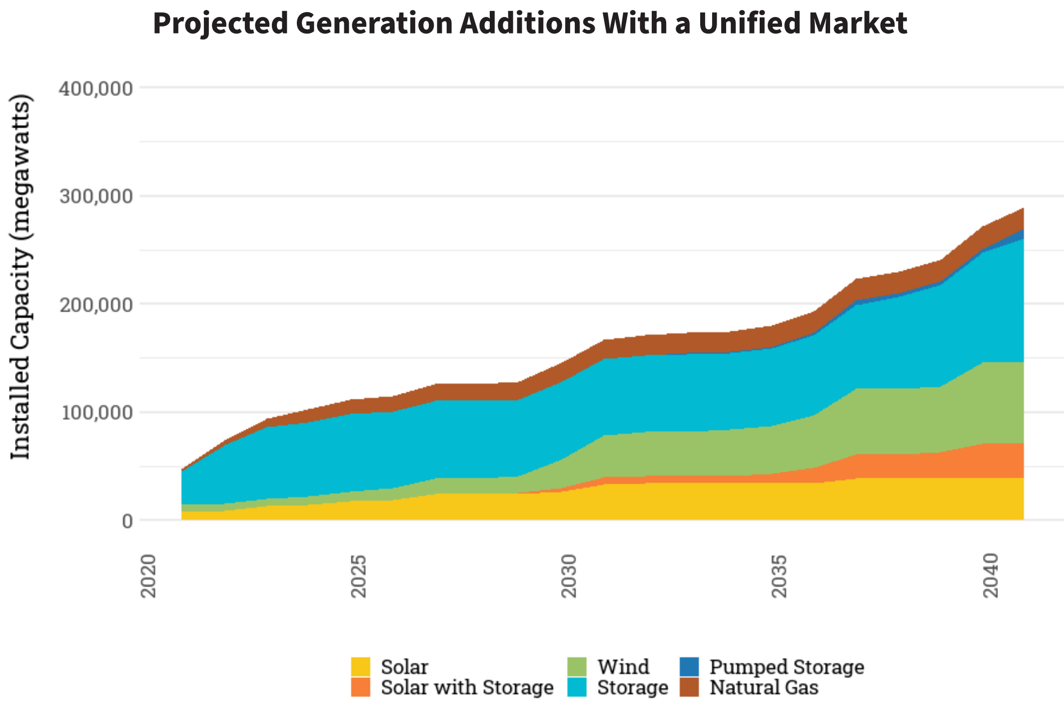
The Council's analysis for this power plan has shown that the costs and risks faced by the region are connected to the policies and decisions beyond our borders. The choices of utilities in the rest of the West on what resources to build and retire directly impacts cost and reliability of power in the region.

To help explore the impacts of electricity markets outside the region, the Council developed several different external generating resource addition projections and looked at the impacts of those different additions on the resource strategy.

Projected Generation Additions With Limited External Market Supply



In one projection, the Council substantially limited the supply of electricity outside the region. This projection met the current renewable portfolio standard or RPS requirements and the clean-energy requirements that limit the types of generation used in some Western states through about 2035, but fell slightly short of meeting these policies after then. By intent, the Western grid outside the Northwest did not have sufficient generation to meet the demand for electricity under stressful conditions. However, the Council did still see a substantial addition of solar power to both meet policy goals and at least partially replace retiring generation.

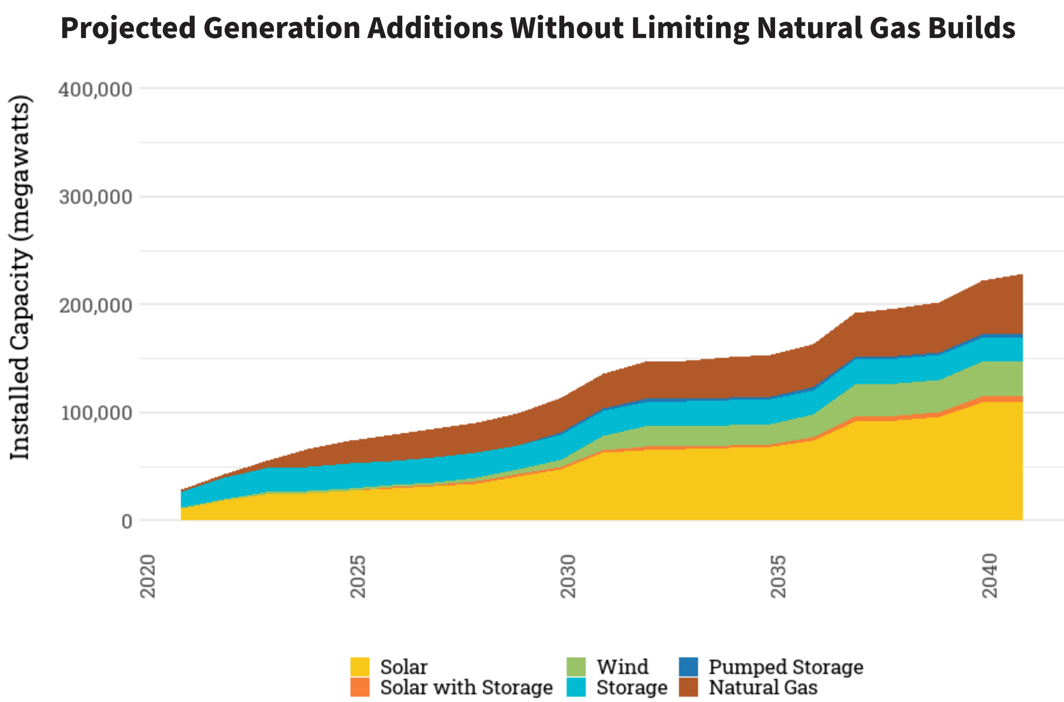


In another projection, the Council also explored resource additions if utilities created a combined approach to planning for new resources and created a unified transmission rate.[65] This was a proxy for how centrally dispatched markets with a consistently applied adequacy standard could impact decisions about resource additions.

Currently the Western electric grid has many different markets with a variety of manners for determining when generating resources are dispatched. There are standards that grid operators must meet set by FERC and NERC, but the operators in an inadequate system may be forced to selectively shut down electricity to parts of the grid to meet these requirements. Consistently applied adequacy standards would make the chances of curtailing electric service both lower and consistent from one region to the next.

In both projections, the Council included limits on the amount of new natural-gas-fired generation that could be built within

65 The important distinction is that access to the transmission system is available at the same rate everywhere, so dispatch is not driven by different transmission charges in different regions of the electric grid. This does not mean a unified transmission rate is necessarily cheaper, nor does it mean that transmission owners would all get the same return. This scenario should not be considered an indication that transmission right owners would either benefit or be disadvantaged from unifying a transmission rate. Discussing how unifying a transmission rate would work is beyond the scope of this scenario analysis.



the Western electricity grid. These limitations were based on both Council expertise and consultation with regional experts on their expectation about resource selection around the West.

However, these limitations substantially increased the addition of solar and wind generation outside the region. To assist in understanding the impact of limiting new natural-gas-fired generation, the Council removed these limits and projected what adding natural gas generation would look like. In this case, the Council saw over 26 gigawatts of natural gas generation added by 2027, and over 55 gigawatts added by 2041. There was also a corresponding reduction in the addition of renewable resources, though there still were over 33 gigawatts of solar generation built by 2027, and over 115 gigawatts built by 2041.

The Council also wanted to isolate the impact of renewable generation included in the regional resource addition to help show the impact of additions within the region compared to additions outside the region. To implement this, the Council removed renewable generation from the resource selections in our analysis and examined the impact to the resource addition.

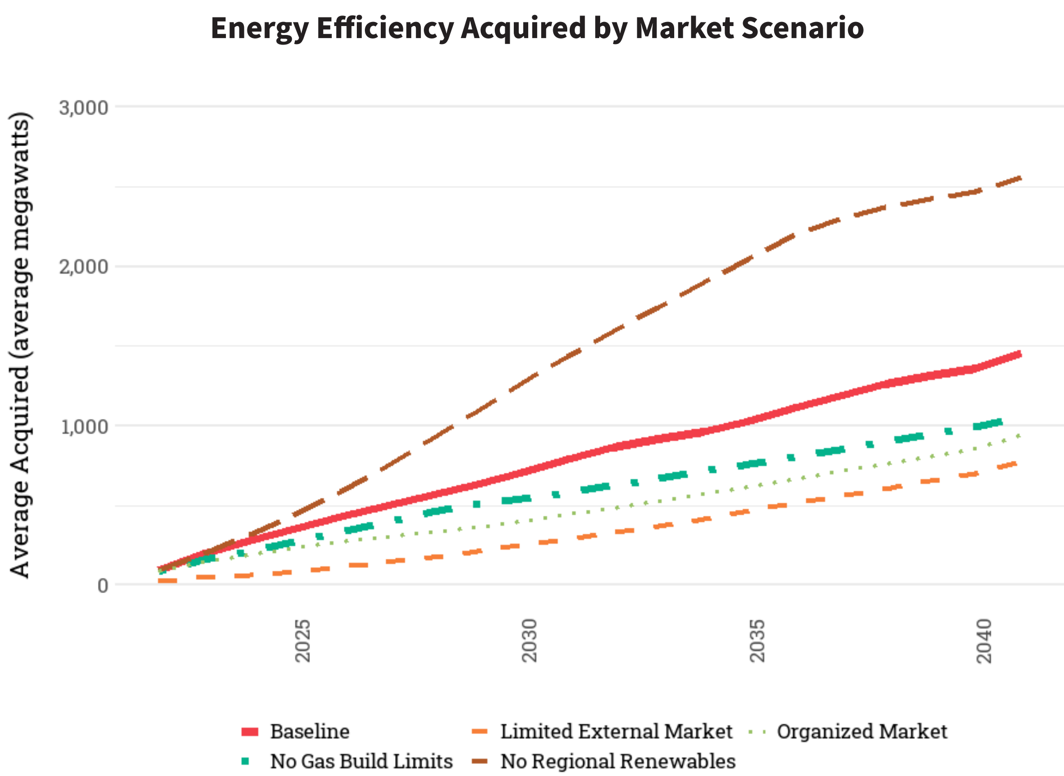
While the regional electricity prices associated with these additions varied, the addition of renewable resources only had minimal changes throughout all these projections except the one where renewable generation in the region was specifically excluded.

This indicates that renewable resource additions at this level are likely required to meet regional policy targets, in addition to being part of the least-cost portfolio under various assumptions about external markets.

In the projection where the Council eliminated regional renewables, there was a requirement for new natural-gas-fired generation to meet adequacy requirements. In this scenario, there was a high probability of adding at least one new power plant.

However, the biggest impact was on the addition of energy efficiency. In the projection where no renewables were built in the region, almost 750 average megawatts of energy efficiency were developed. In the projection with limitations on the external market, less than 150 average megawatts were developed.

Average Renewable Resource Builds by Market Scenario



These results show that while the regional addition of renewable generation was not particularly sensitive to electricity market prices, the addition of energy efficiency was sensitive.

Early Retirement of Coal Generation

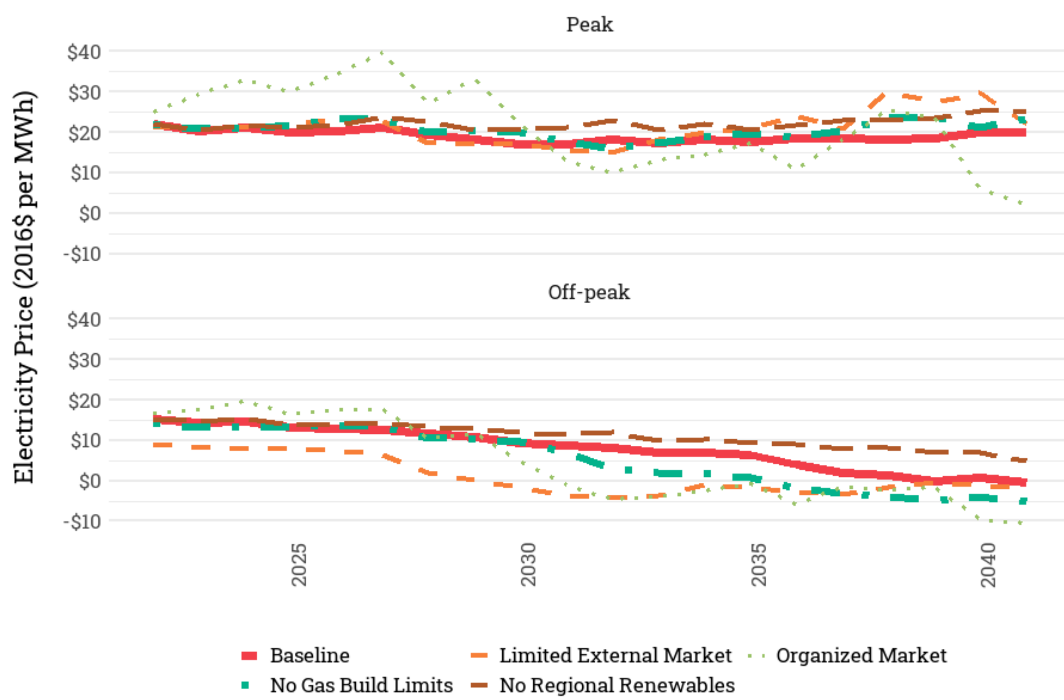
Since the last power plan, utilities in the region and outside the region have announced the retirement of coal-fired power plants at dates that precede the end-of-useful-life dates that have been previously assumed in analyses by the Council and others. The Council understands that there is risk in retiring resources sooner than planned, especially coal-fired generation. This scenario explores this risk using the coal-fired generation fleet in the West. There are likely other types of generation that could have retirement dates accelerated based on economics or regulation. The Council did not analyze the likelihood of early retirement for all types of generation. Thus, this should be considered a directional analysis that was used to help the Council understand this observed risk.

To implement this, the Council assumed that all regional coal-fired power plants were retired by the end of 2026. For coal plants outside the region, the Council assumed that all plants were retired by 2030.[66]

Our analysis shows with this scale of retirement, emissions in the West would decrease just under 40 percent after all the coal plants are fully retired. Emissions in the Northwest would decrease over 80 percent.

The emissions reductions are greater in the region because the hydro generation in the region has resulted in a smaller natural gas-fired generation fleet relative to the rest of the West.

Regional Electricity Price by Market Scenario



66 These dates are not intended to represent likely dates that the coal-fired power plants would retire, rather they are intended to be a stress test of the power system and be informative on coal-fired generation's impact on greenhouse gas emissions.

Regional Coal Plant Unit Retirement Scenario Assumptions

Coal Plant Unit	Nameplate Capacity (MW)	Announced/ Existing Retirement Date (EOY)	Baseline Conditions Retirement Assumptions[67]	Early Coal Retirement Scenario Assumptions
Colstrip Unit 1	358	2019		
Colstrip Unit 2	358	2019	Retired	Retired
Boardman	601	2020	Retired	Retired
Centralia 1	730	2020	Retired	Retired
North Valmy 1	277	2019[68]/2021	Retired	Retired
Centralia 2	730	2025	2025	2025
North Valmy 2	289	2025	2025	2025
Jim Bridger 1	608	2023	2023	2022
Jim Bridger 2	617	2028[69]	2028	2026
Colstrip 3	778	–	2037	2025[70]
Colstrip 4	778	–	2037	2025
Jim Bridger 3	608	–	2037	2026
Jim Bridger 4	608	–	2037	2026

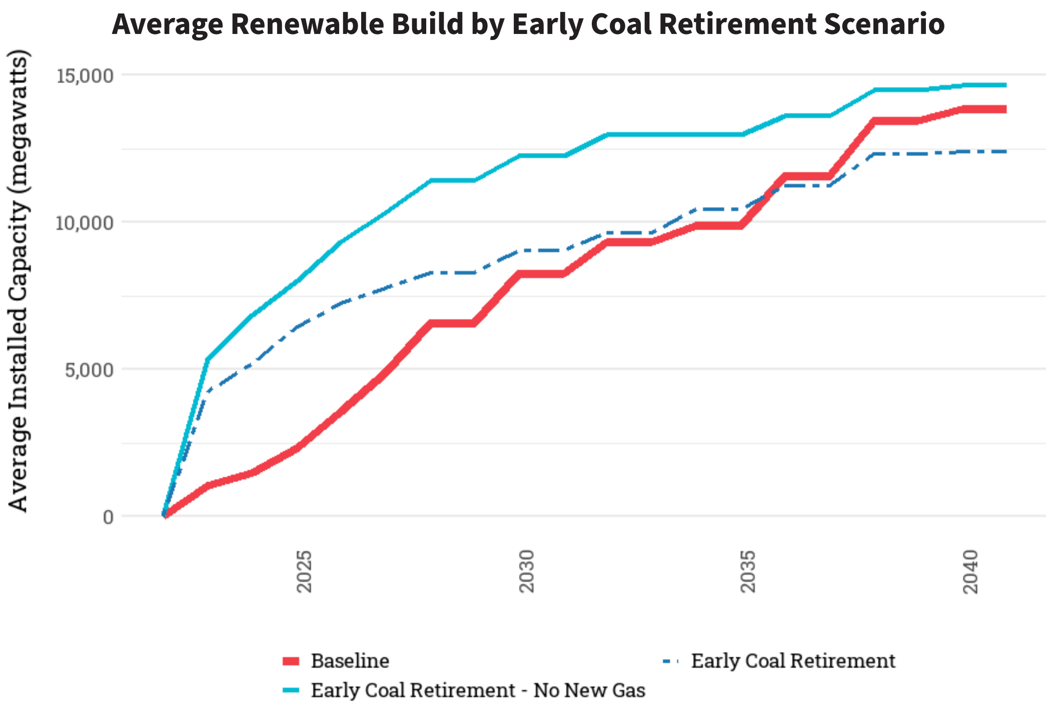
Without limiting the types of new generation, the expected resource addition by 2030 includes around 1,400 megawatts of nameplate capacity of new natural-gas-fired generation. Considering the decisions that would lead to early coal retirement, it seems unlikely that new natural-gas-fired generation would be considered for replacing retired coal generation. By eliminating new natural gas-fired generation from consideration, the expected renewable-energy addition in the region substantially increases.

67 For our baseline assumptions we use either the announced retirement dates or end-of-useful life dates used in utility IRPs.

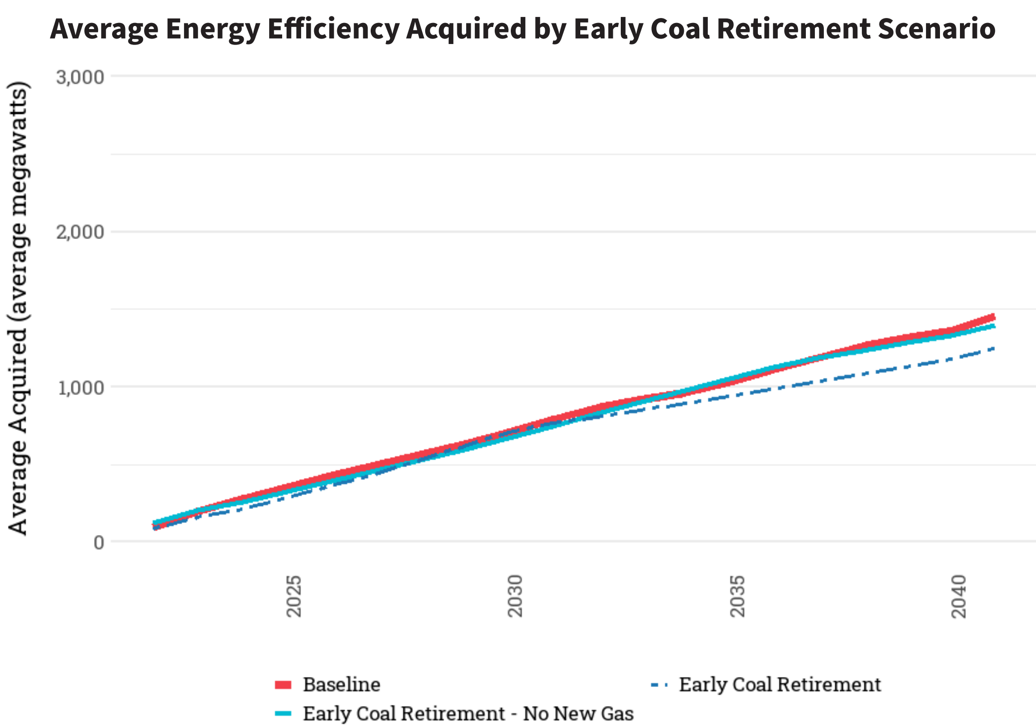
68 Idaho Power ended its participation in this unit in 2019.

69 PacifiCorp and Idaho Power are still working out details of the accelerated retirement of Bridger 2, this date should be considered tentative.

70 For a potential early retirement date for Colstrip Unit 3 and Unit 4, 2025 was selected based on the Washington state utility requirements in the Clean Energy Transformation Act.



While the Council sees a response in the renewables addition for this scenario, there is relatively little change in the addition of energy efficiency.



The Council also sees an expected increase of 7.2 percent in residential electricity bills in this scenario.

Robustness of Energy Efficiency

Energy efficiency has been the cornerstone resource of the Northwest since the first power plan. For this scenario, the Council explored assumptions about the supply of energy efficiency and the drivers that impact acquiring more or less of this resource.

Specifically, the Council looked at the impacts of differing regional adequacy needs, rate of acquisition, the amount available, the contribution to regional capacity needs, and the impact of varying our treatment of emissions on portfolio costs. The Council examined how it collects supply curves for portfolio analysis and then ran a sensitivity on how other resource decisions would change under high and low acquisition of energy efficiency.

When the Council increased or decreased the regional adequacy need, especially when testing an extremely high regional need to develop new generating resources, the energy efficiency resource acquired came close to doubling.

Altering the rate of acquisition of energy efficiency and the amount available resulted in more and less energy efficiency acquired for faster and slower ramps respectively. The increase and decrease of energy efficiency were driven by the differing availability of efficiency in the early years of the study. However, in both cases the Council also observed an increase in the overall system cost. In the case where there was an increase in energy efficiency, there was not a significant difference in the unit cost of the energy efficiency being acquired, but the increased amount resulted in more money spent on the resource in total. In the case of decreasing energy efficiency acquisition, the increased costs manifested in purchasing more expensive resources. While acquiring more energy efficiency absent other changes would increase the reliability of the system, the Council saw the faster acquisition of energy efficiency alter other resource decisions in a manner that resulted in no meaningful increase in the reliability of the system.

The contribution of energy efficiency to capacity needs is estimated using the best data that are available to the Council on the timing of the use of electricity. However, some of these data are outdated, and the region is currently conducting research that will allow for updated information to be used in the next power plan.[71] The Council tested how resource additions would respond if the capacity contribution of energy efficiency was increased. In part, this test assumed that the updated data may show better alignment between peak electricity needs and energy efficiency. The test showed changes in other types of resources built in response to the overall change in system need based on the contribution of energy efficiency to the peak

71 neea.org/data/nw-end-use-load-research-project

system need. However, the Council did not see additional acquisition of energy efficiency in this test.

When the Council constrained energy efficiency to look at the impact of suboptimal acquisition, acquiring more energy efficiency led to a more expensive system by displacing less expensive resources and by acquiring more resource than was needed. With less energy efficiency acquired, the result was a less reliable system.

In our baseline for our analyses, the Council incorporated an emissions cost based on the Social Cost of Carbon from the Intergovernmental Panel on Climate Change into the portfolio cost. For this scenario the Council tested the impact of this on the acquisition of energy efficiency. When removing this impact on portfolio costs, the Council saw some reduction in the near-term acquisition of energy efficiency and a larger reduction in the total energy efficiency acquired over the 20-year plan duration.

Analyze the Bonneville Portfolio

Bonneville is a central part of the Northwest electric system. A large portion of the transmission in the region is owned and operated by Bonneville. The Council considers a broad array of information from all the various analyses included in this plan when making recommendations to Bonneville. One key part of that perspective is understanding the obligations Bonneville has to provide electricity and the federal resources and contracts that are designated to be used to meet those obligations – that is, the Bonneville portfolio.

The Council analysis see a small need for additional resources. The Council describes the existing federal resource capability and

Energy Efficiency Acquired in Robustness of Energy Efficiency Tests

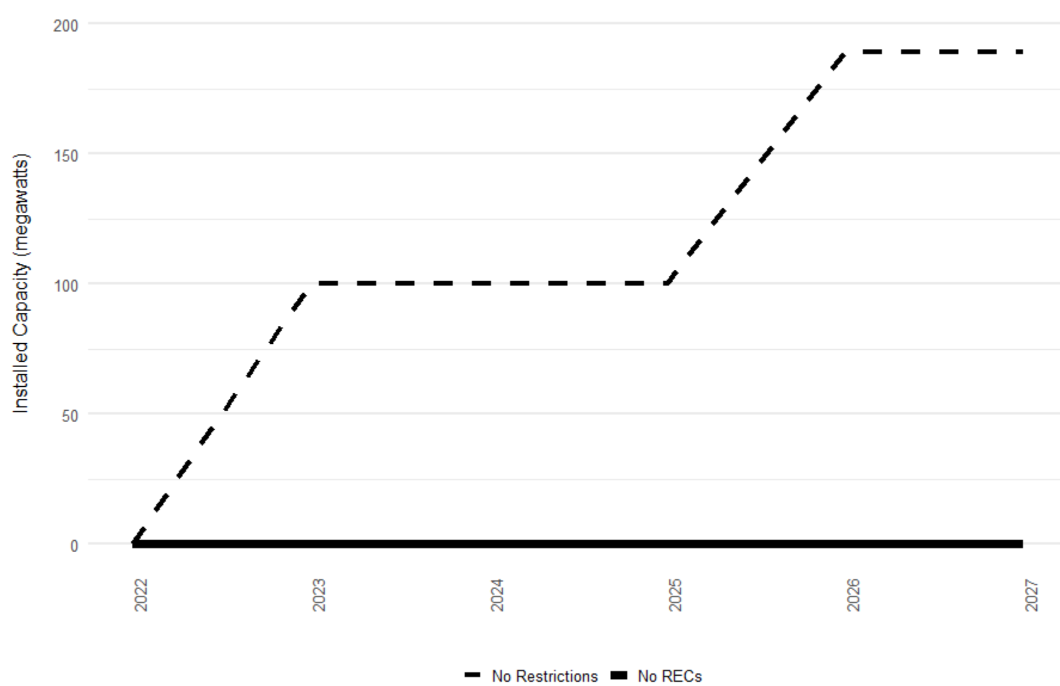
Scenario / Test	Energy Efficiency Acquired (average megawatts)	
	2027	2041
Baseline Conditions	500	1462
Change Supply Curve Binning	470	993
Increased Acquisition Ramp and Potential	1362	2562
Decreased Acquisition Ramp and Potential	370	1235
No Emissions Related Portfolio Cost	175	780
Increased Adequacy Requirements	932	2656

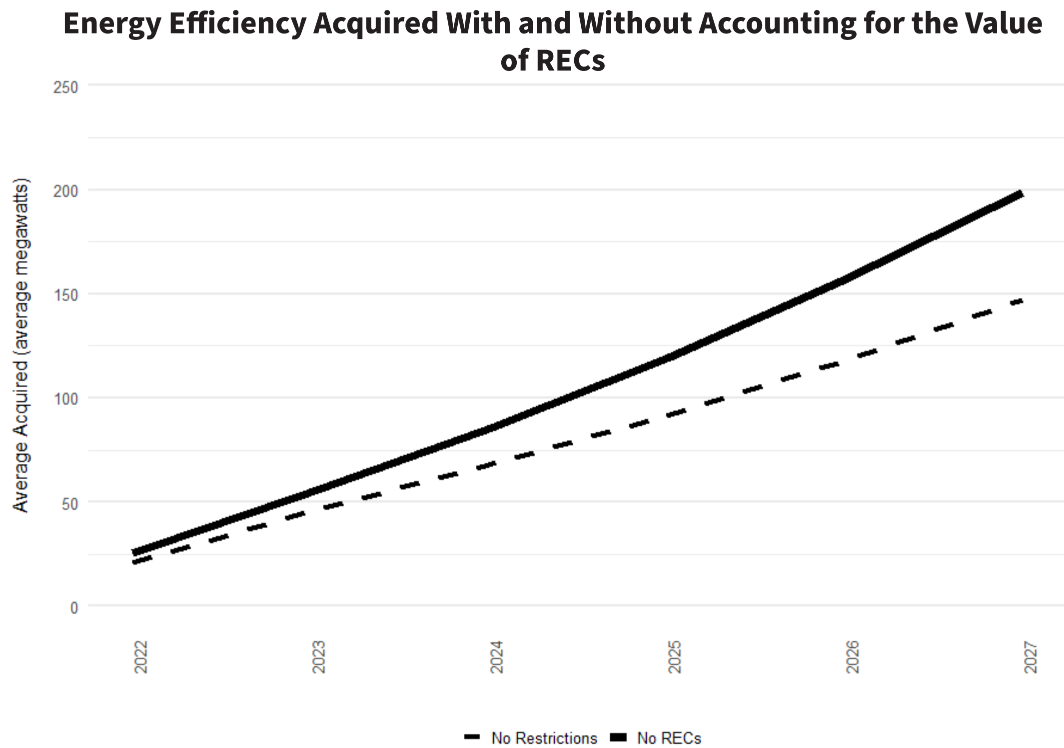
obligations in *Section 7: Forecast of Federal Power Resources and Obligation to Provide Electricity*. Under many of the forecasts for an increase in the Bonneville obligation, the Council sees that existing resources are sufficient to meet the need. However, there are infrequent circumstances where an increase in the demand for electricity exceeds the seasonal firm energy in the federal power system. Our analysis shows the least-cost way to meet these needs is a combination of energy efficiency, demand response, and renewable resources.

Part of this analysis was looking at the cost of resources. When examining the cost of renewable resources, the treatment of renewable energy credits (RECs) altered the amount of renewable generation additions to the portfolio. When the RECs were assumed to offset the cost, more renewable resources were selected as part of the portfolio. However, currently Bonneville passes RECs through to its customer utilities, so they do not accrue value to the Bonneville portfolio. When excluding the value of the RECs, the addition of renewable generation is much more limited.

The treatment of RECs also impacts the amount of energy efficiency acquired. Because renewable resources meet part of the energy need, there is a reduced need for energy efficiency.

Renewables Build With and Without Accounting for the Value of RECs



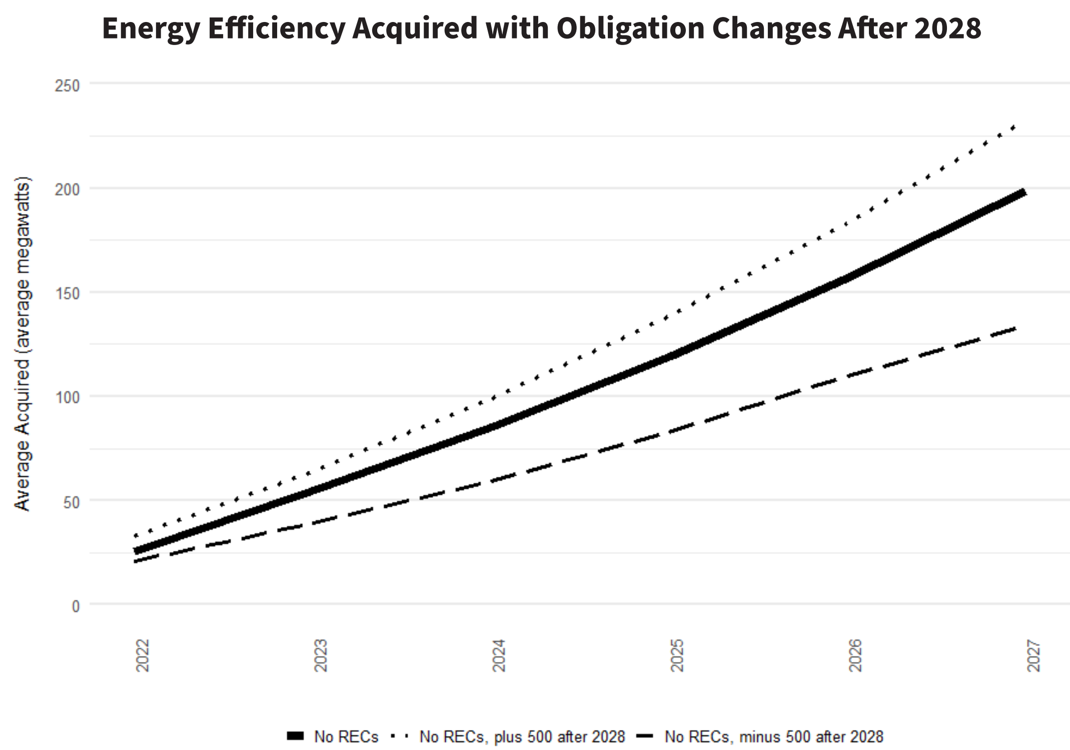


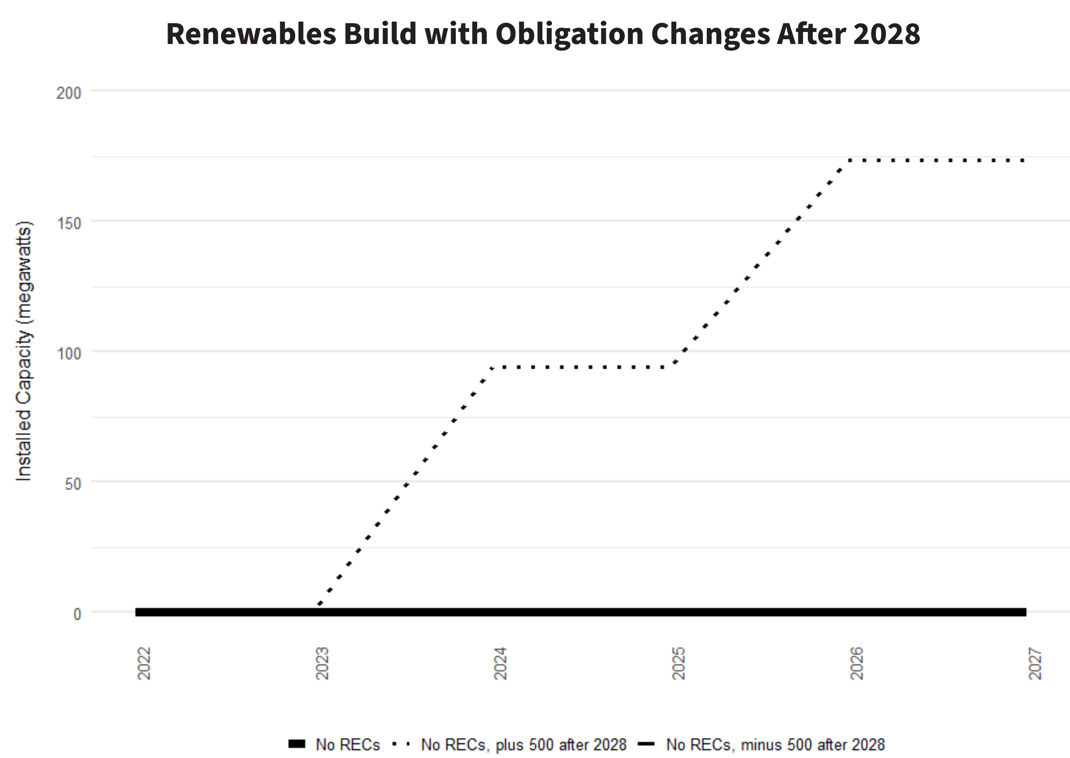
The Council also tested the demand response measures seen to be low-cost and part of the resource additions in the regional analyses. The measures examined were demand voltage regulation (DVR) and time-of-use rates (TOU). These measures reached 300 megawatts of capacity by 2027 in the portfolio.

The Council also examined the implications of a change in obligation after the Bonneville contracts expire in 2028.[72] The purpose was to see if there would be near-term changes in resource additions based on the obligation change in 2028. To test this, the Council added and removed 500 average megawatts from the Bonneville obligation in 2028. When adding obligation, the Council saw additional near-term resource additions as the least-cost solution. When removing it, the Council saw lower near-term resource additions. Adding to the obligation in 2028 increased the addition of energy efficiency by 2027 by 35 average megawatts. Decreasing the obligation removed around 65 average megawatts of energy efficiency.

Similarly, for renewable resources – when excluding the value of RECs – our analysis shows an increase of almost 175 megawatts

72 The eventual size of Bonneville's obligation to serve after 2028 adds a level of uncertainty to our needs forecast that may not be fully realized until the end of the plan's action period and may require further analysis by the Council to determine the full impact of Bonneville's future contractual obligations.


Energy Efficiency Acquired with Obligation Changes After 2028
Average Acquired (average megawatts)
0
50
100
150
200
250
2022
2023
2024
2025
2026
2027
No RECs
No RECs, plus 500 after 2028
No RECs, minus 500 after 2028


Renewables Build with Obligation Changes After 2028
Installed Capacity (megawatts)
0
50
100
150
200
2022
2023
2024
2025
2026
2027
No RECs
No RECs, plus 500 after 2028
No RECs, minus 500 after 2028

of nameplate capacity additions by 2027 when the obligation increases in 2028. Decreasing the obligation does not impact near-term resource additions and shows no additions of renewable resources after 2028.

Greenhouse Gas Regulation Cost and Impacts

The Council has been analyzing greenhouse gas emissions and the impact of regulation to reduce emissions on the electricity sector throughout most of its history. Analysis of emissions first appeared in the 1991 Power Plan.[73] However, in recent years the scope and variety of regulation related to emissions have expanded, not just in the region but throughout the West.

This plan has aggregate renewable energy requirements and clean-energy requirements. The Council also included the social cost of carbon from the Intergovernmental Panel on Climate Change as part of the portfolio cost calculation. However, the Council did not assume generating resources that emit greenhouse gases would dispatch with emission pricing included in their variable cost.

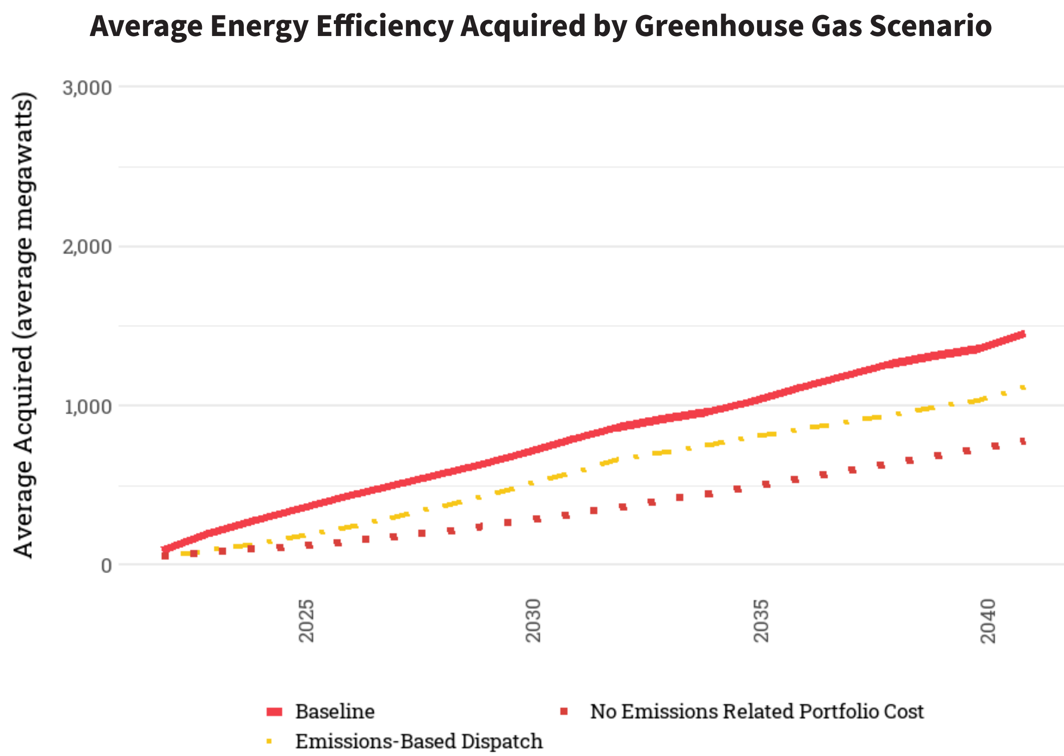
The Council developed this scenario to explore the implications of regulation throughout the West intended to limit or reduce greenhouse gas emissions.

The Council started by examining the implications for adding generating resources outside the region. Like the scenario work on organized and limited markets, this scenario looked at what resources would be built if limitations on new natural gas generation were removed. The scenario showed the addition of almost 60 gigawatts of natural gas generation by 2040 when the scenario was not constrained by resource options.

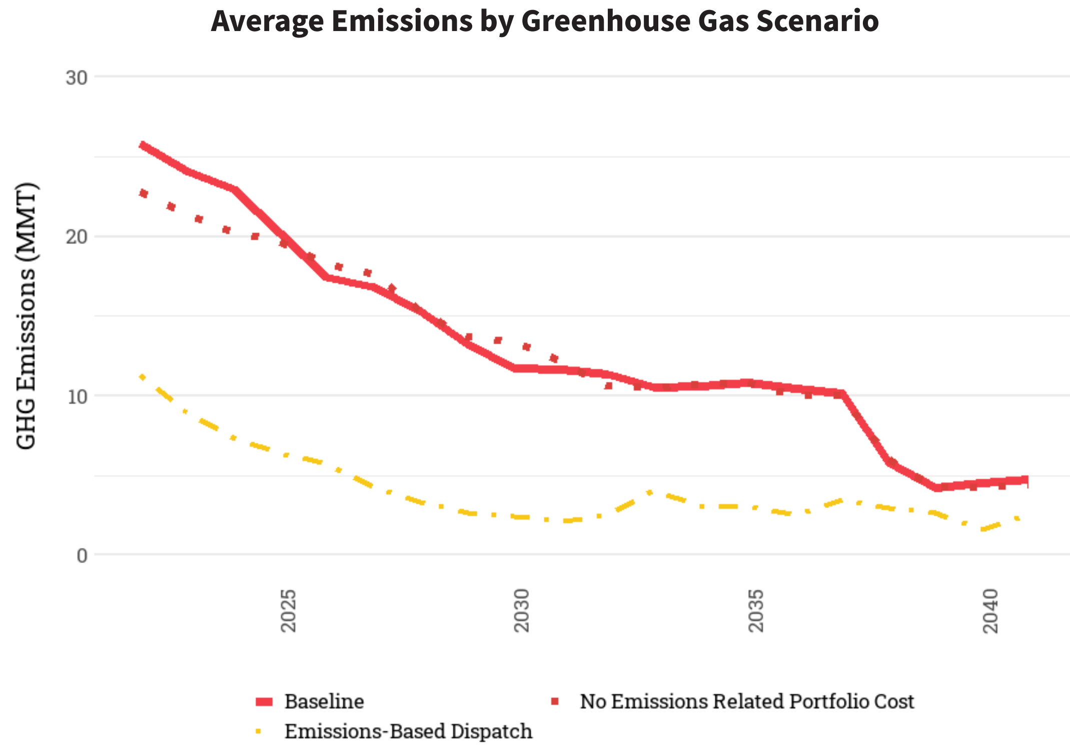
The Council also looked at the implications of explicit emissions pricing included in the dispatch of all resources in the West. In this case, renewable resource additions increased by just over 13 percent in 2040.

The Council's analysis shows that emissions regulation has a substantial impact on the resource strategy. While the Council does not set emissions-related policies either in the region or outside the region, the Council considers the impacts of these policies when making recommendations for a resource strategy. The analysis showed that both including the price of emissions in resource dispatch and removing emissions-related portfolio costs reduced the energy efficiency acquired.

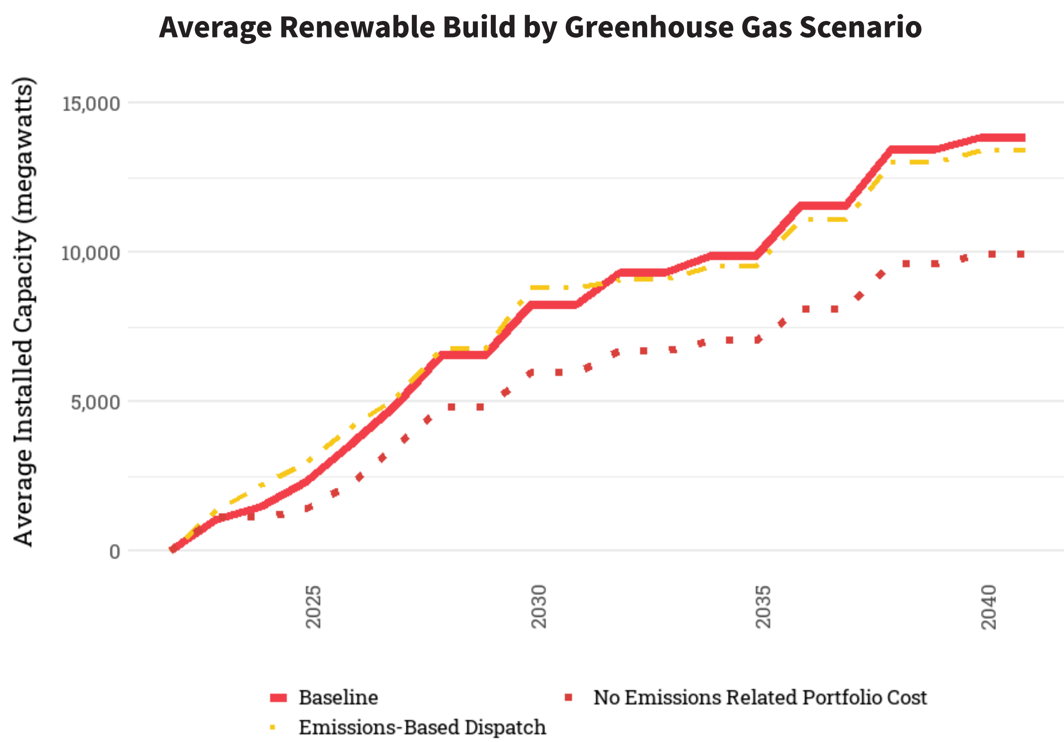
73 nwcouncil.org/reports/1991-northwest-conservation-and-electric-power-plan



While implementing an emissions-based dispatch slightly increased the number of renewable resources built, removing emissions-related portfolio costs decreased the amount of renewable resources built to around 3,500 megawatts of nameplate capacity by 2027.



There was little impact on regional emissions when removing the emissions-related portfolio costs, but changing how regional resources dispatch to include an emissions-based price substantially reduced the amount of emissions in the region.



Pathways to Decarbonization

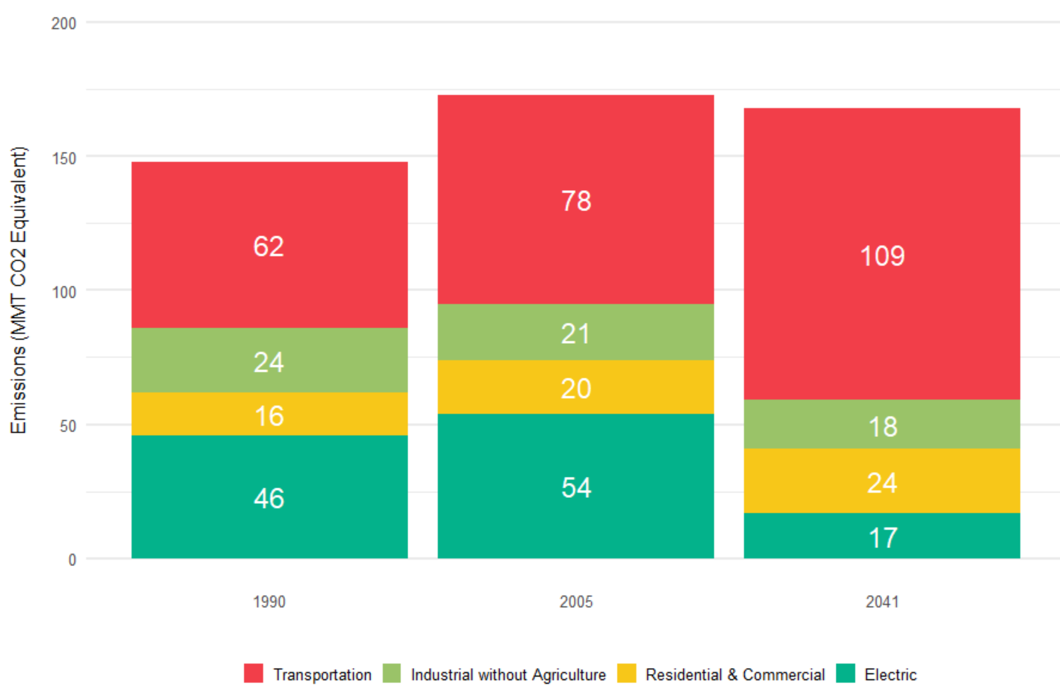
The states of Oregon and Washington have set goals and limits on future greenhouse gas emissions. Oregon's goal is to reduce emissions 80 percent below 1990 levels by 2050. Washington's goal is to reduce emissions 95 percent below 1990 levels and be at net-zero emissions by 2050.

These goals include the electricity sector in a broad range of emissions. To analyze the impacts on the electric system in this scenario, the Council forecast the region's demand for natural gas, as well as transportation fuels. Including the impact of emissions from the use of these fuels, the resulting estimates show that regional emissions will rise compared to 1990 levels in our baseline conditions.

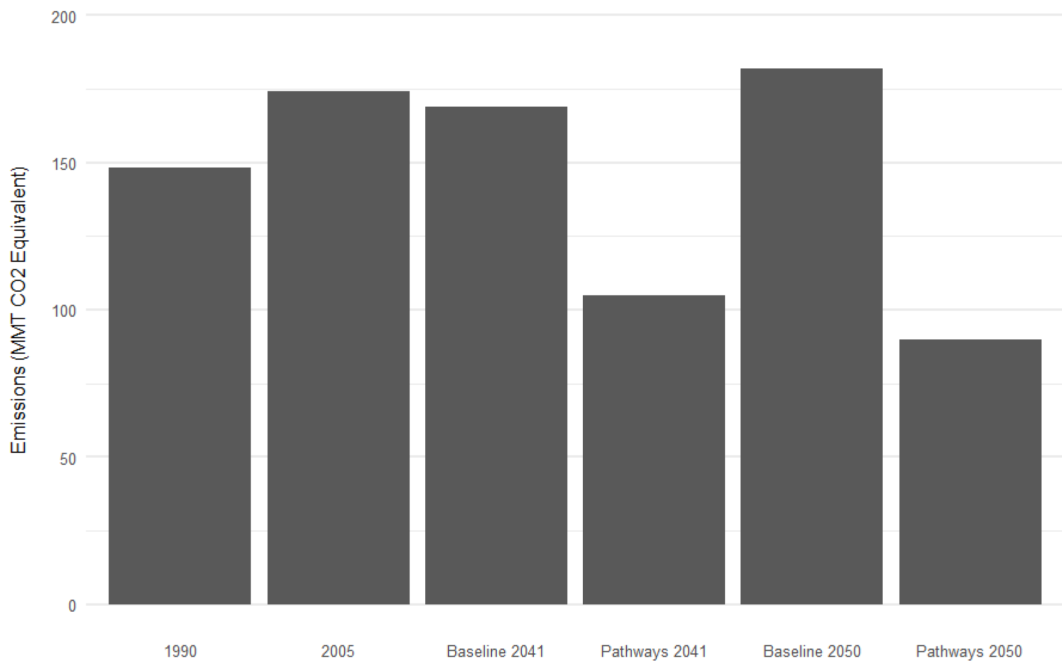
By 2041 under baseline conditions for the analysis, most regional emissions will be associated with the use of fuel for transportation. One potential approach to reducing emissions in the transportation sector would be the electrification of transport and potentially the production of hydrogen through electrolysis as a non-greenhouse-gas-emitting fuel for use in vehicles or other applications. The analysis shows it would be possible to reduce emissions by almost 27 percent by 2040, but it would require more than 12 gigawatts of additional electricity to meet the demand that new transportation technologies would place on the electricity grid.

However, even adding the reduction from aggressive electrification of transportation

Expected Sector Emissions Based on Baseline Conditions



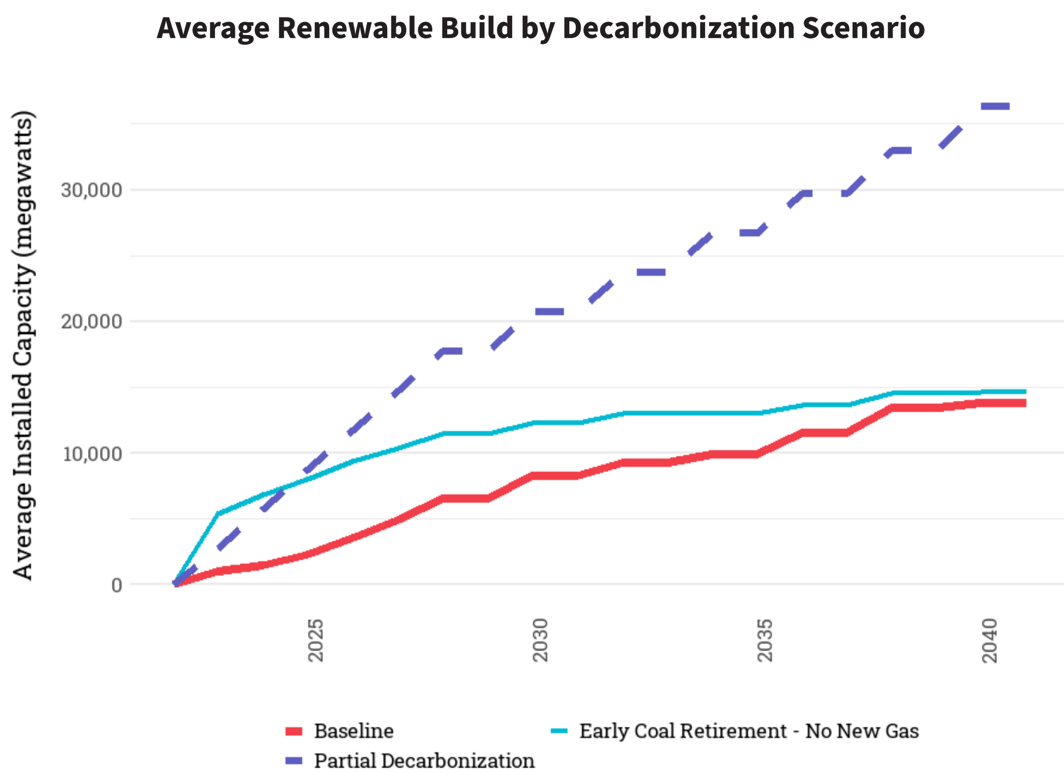
Regional Emissions from Energy Used in Residential, Commercial, Industrial, Agriculture, and Electric Utilities



with a collection of equally aggressive policies to reduce other emissions in the broader regional energy sector, the analysis does not show a path to getting to the targeted reductions within the energy sectors using the current technologies. The policies the Council tested include replacing vehicles and appliances and equipment in homes, businesses, and manufacturing at an accelerated but possibly obtainable pace.

Looking at the scope of change in this analysis, the Council decided the incremental demand to the electric system was beyond the resource expansion that could be supported by the structure of our analysis. To test the impact on the resource strategy, the Council removed a substantial proportion of the demand associated with the production of hydrogen by electrolysis. While this reduced the likelihood of reaching the Oregon and Washington targets for reducing greenhouse gas emissions, it provided a directional analysis of the possible impacts to resource additions. It also still represents aggressive emissions reductions relative to baseline conditions in the analysis. By 2040, this more moderate but still aggressive emission reduction increased the demand for electricity by just over 52 percent.

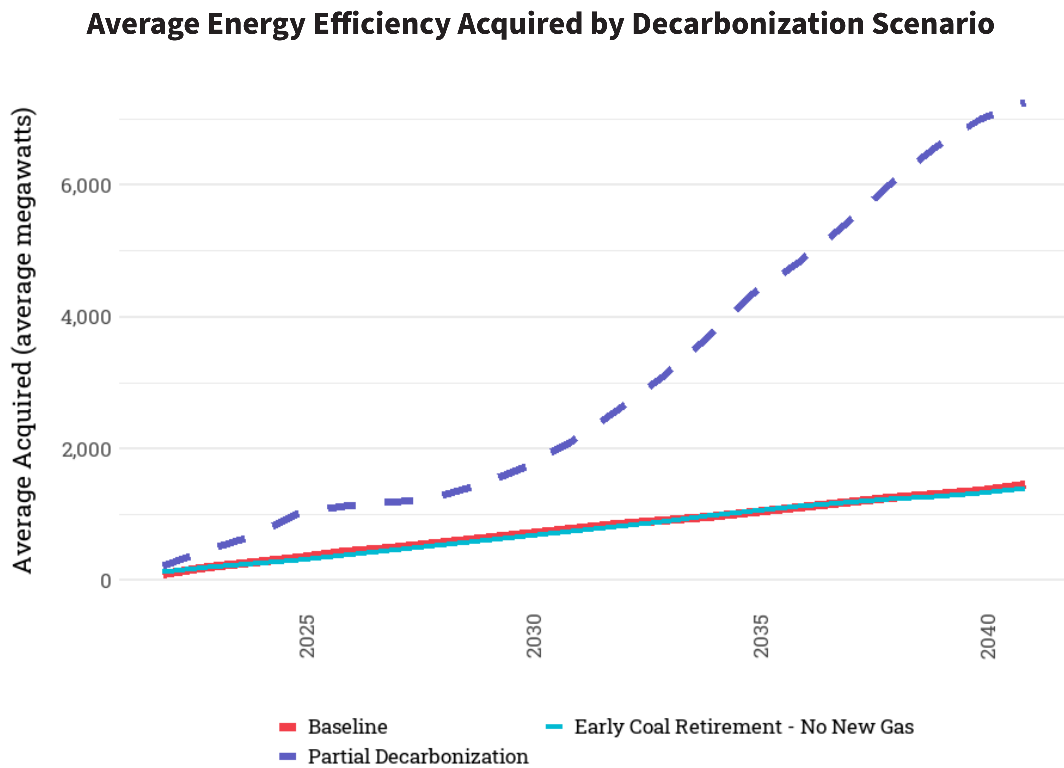
In response to this increased demand, the analysis showed a substantial increase in the addition of renewable resources relative to other scenarios the Council explored.

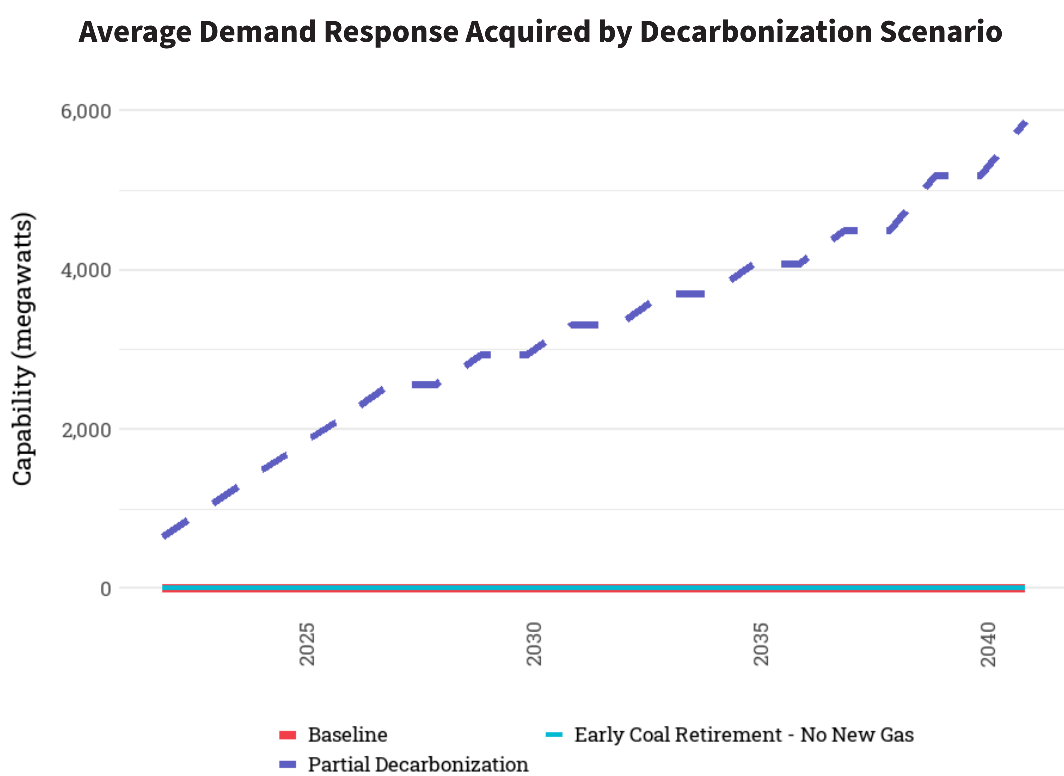


The Council also altered the supply of energy efficiency and demand response to incorporate the additional anticipated demand for electricity. This analysis showed substantial increases in energy efficiency.

The analysis also showed a substantial uptake of demand response to support system adequacy (next figures).

The resource addition also included an expected 800 megawatts of battery storage capacity. Part of the renewable resource addition included an expected 2,100 megawatts of solar generation nameplate capacity with on-site batteries. In addition, there were some conditions where the increased demand resulted in a conventional geothermal power plant being part of the least-cost resource addition for this scenario.


Average Energy Efficiency Acquired by Decarbonization Scenario
Average Acquired (average megawatts)
6,000
4,000
2,000
0
2025
2030
2035
2040
Baseline
Early Coal Retirement - No New Gas
Partial Decarbonization


Average Demand Response Acquired by Decarbonization Scenario
Capability (megawatts)
6,000
4,000
2,000
0
2025
2030
2035
2040
Baseline
Early Coal Retirement - No New Gas
Partial Decarbonization

Section 7: Forecast of Federal Power Resources and Obligation to Provide Electricity

What the Northwest Power Act Requires of the Council Regarding Bonneville's Resource Acquisition

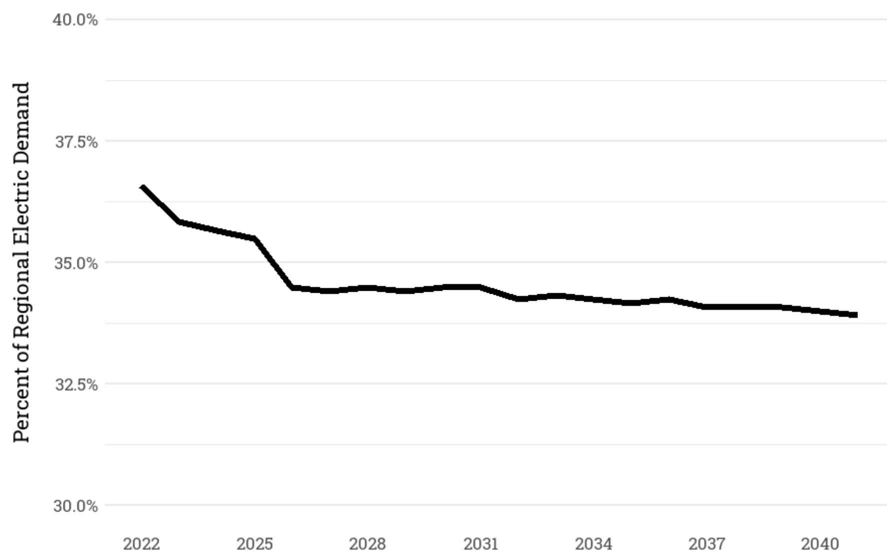
The Northwest Power Act directs the Council to "set forth a general scheme for implementing conservation measures and developing resources […] to reduce or meet the Administrator's obligations." The Council also is required to prepare a demand forecast of at least 20 years and "a forecast of power resources estimated by the Council to be required to meet the Administrator's obligations." Further, the Council is required to include, to the extent practicable, an estimate of the types of resources from which such power should be acquired.

To accomplish these requirements, the Council forecasts both demand for electricity from the Bonneville Power Administration and the electricity currently produced by the Federal Columbia River Power System, which is marketed by Bonneville. Further, the Council is required to make a recommendation to the Bonneville administrator on the amount of power needed to meet or reduce the agency's obligation and what types of resources that power should be acquired from. Our recommendation is included in *Section 8 Recommendation for the Amount of Power and Resources Bonneville Should Acquire to Meet or Reduce the Administrator's Obligation*.

Forecast of Demand for Electricity from the Bonneville Power Administration

The Council estimates[74] that the proportion of the regional demand for electricity that Bonneville is obligated to supply[75] with the federal power resources starts at just under 37 percent in the first year of the 20-year power plan forecast period and falls to just above 32 percent by the end. Through 2028, this estimate is based on the current Bonneville Regional Dialogue contracts.[76] After 2028 the Council assumes the contracts will be substantially similar, but in our scenario analysis we test the implications of both, adding to and subtracting from Bonneville's obligation. That is, in our

Estimated Bonneville Obligation as a Percentage of Annual Regional Electric Demand



This graph shows that Bonneville's obligation decreases as a proportion of the total regional demand for electricity through 2026. After 2026, Bonneville's obligation increases slightly.

74 The Council greatly appreciates Bonneville supplying data and supporting our analysis, which enabled the estimates included in this section. However, these estimates do not correspond to any publicly released forecast from Bonneville, nor are they intended to represent the forecasts Bonneville uses for its various functions and purposes.

75 While Bonneville has broad obligations under the Northwest Power Act, we use "obligation" to refer to the amount of electricity that will be requested from Bonneville by entities that have a statutory right to have Bonneville supply electricity to them.

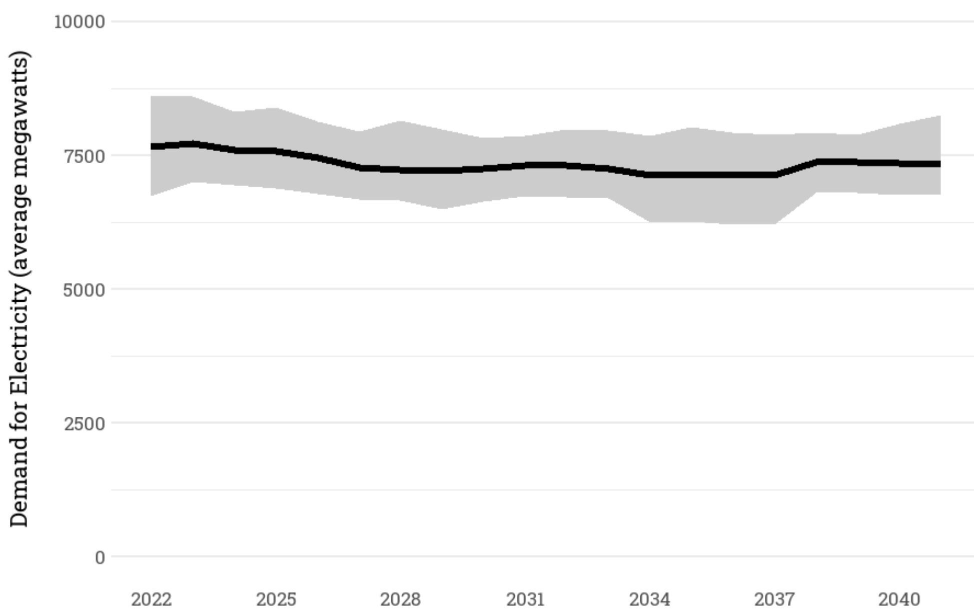
76 www.bpa.gov/p/Power-Contracts/Regional-Dialogue/Pages/Regional-Dialogue.aspx

analysis we anticipate that Bonneville and its customers will sign new contracts, but we also acknowledge there is uncertainty about any contracts that may follow the current Regional Dialogue.

or decrease based on temperatures in the region.

Subscription obligations are driven by the amount of power the federal resources generate. Temperature does not impact the

Forecast Electric Demand Bonneville Is Obligated to Supply



The Council's forecast includes estimates of climate-change impacts. However, Bonneville is less affected by temperature than is the region. To incorporate the impacts of temperature, we partitioned Bonneville's obligation into three categories: contract obligations, subscription obligations, and temperature-sensitive obligations.

Contract obligations are fixed amounts of electricity that Bonneville is obligated to deliver. These amounts do not increase

total amount of power Bonneville is obligated to deliver in this category, but it may impact the timing of when that power is delivered.

Temperature-sensitive obligations are deliveries that respond to weather extremes and generally are less than half of Bonneville's obligation, but that changes between different quarters of the year and between forecast years.

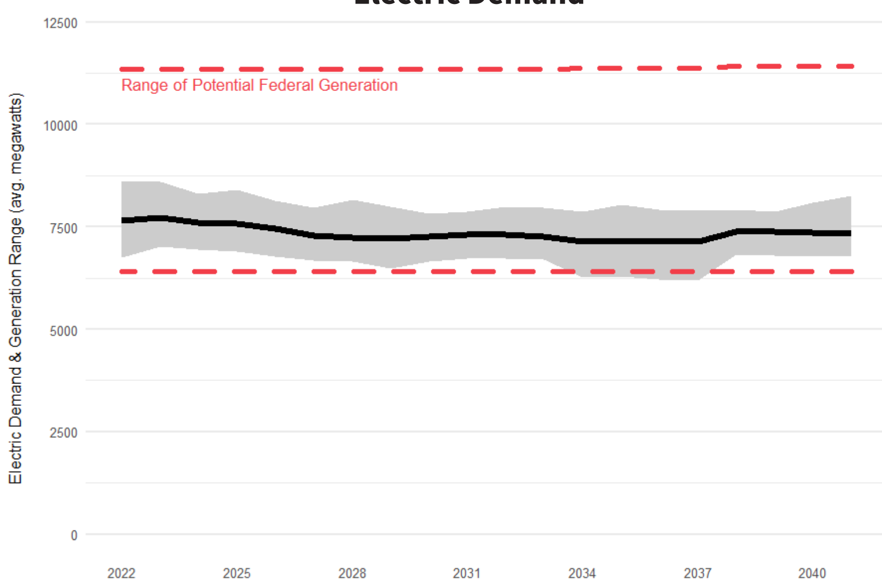
Percentage of Bonneville's Obligation Categorized as Temperature-Sensitive

	Fiscal Year			
	2023	**2025**	**2027**	**2031**
Q4[77]	43.2%	42.5%	43.0%	42.8%
Q1	41.8%	41.5%	42.2%	41.9%
Q2	46.4%	45.9%	47.4%	47.7%
Q3	45.3%	45.1%	46.2%	46.6%

Forecast of Electricity Produced by Federal Resources and Marketed by Bonneville

The Council estimates that generation from the Federal Columbia River Power System generally varies from a minimum of just over 6,400 average megawatts to a maximum of over 11,000 average megawatts. This range is mostly a function of the change in hydroelectric generation from year-to-year. In a year with plentiful water from regional rain and snowpack, the amount of generation from the system far exceeds Bonneville's obligations. In these situations, the excess

Electricity Produced by Federal Resources Compared to Electric Demand



77 The Bonneville and Council fiscal year is October 1 to September 30. The quarters indicated are the calendar year quarters. Thus, Q4 is the first quarter of the fiscal year and contains the months of October, November, and December. The first month of the 2023 fiscal year is October 2022.

electricity would either be sold, scheduled[78] in the secondary markets, or spilled at the federal dams without generating electricity.

Estimated Bonneville Need for Electricity

While under many circumstances Bonneville has surplus electricity relative to its obligation, there are some infrequent circumstances where the electricity produced by the federal system is less than the amount of power Bonneville is obligated to supply. For this analysis, the Council worked with Bonneville staff to adapt the approach taken in the Bonneville Needs Assessment.[79] This approach uses a "critical" energy amount[80] from the federal hydroelectric system to establish a risk preference on the amount of energy from that system set aside to meet the Bonneville obligation. This is added to the non-hydro-based resources in the federal system, and contracts and transmission losses are subtracted to determine the federal system's capability to supply electricity under critical circumstances.

Bonneville, in coordination with the Council, ran simulations using models tuned to estimate the federal system output. These simulations were adapted to the methods the Council uses in its regional modeling. Four years were run through the simulation, as detailed in the following table.

Expected Federal System Generation Under Critical Circumstances in Average Megawatts

	Fiscal Year			
	2023	**2025**	**2027**	**2031**
Q4	7157	7107	6995	7233
Q1	7000	6991	6845	7348
Q2	6007	6037	5843	5521
Q3	7086	7205	7091	6222

The Council's estimate of Bonneville's need for electricity is based on the difference between the Council's forecast of the electricity demand Bonneville is obligated to serve and the expected federal system generation under critical-energy circumstances. The analysis assumes limited market purchases to meet load variation in

78 There are times when the generation from the federal system is not sold in the secondary market but is still scheduled to be exported. See Bonneville's Oversupply Management Protocol, www.bpa.gov/Projects/Initiatives/Oversupply/Pages/default.aspx.

79 The Bonneville Needs Assessment is included in the BPA Pacific Northwest Loads and Resources Study, commonly referenced as the White Book. www.bpa.gov/p/Generation/White-Book/Pages/White-Book.aspx.

80 In this case, "critical" is defined by looking over the range of simulated generation when using regulated flows defined by the climate-change-based precipitation estimates for each of 14 periods, corresponding to the calendar months except April and August are split at the end of the 15th day to form two periods each. In each of these periods, we take an amount of generation that only one out of every 30 simulations would be below (or the 3.33 percentile of the simulated generation for each period).

a particular quarter or season. This results in an estimated margin between critical-energy generation and electricity demand.

For example, in the first quarter of the 2023 fiscal year (October to December of 2022), the Council estimates Bonneville would have sufficient electricity as long as the federal generation under critical circumstances (estimated at 7,157 average megawatts) can meet 88.5 percent or more of Bonneville's need for electricity.

Margin of Critical Resource to Electric Demand

	Fiscal Year			
	2023	**2025**	**2027**	**2031**
Q4	88.5%	88.8%	93.7%	98.0%
Q1	81.6%	83.3%	86.6%	94.0%
Q2	86.6%	88.3%	89.8%	84.1%
Q3	94.6%	96.8%	98.8%	86.6%

When the available federal generation is less than the estimated margin, we project Bonneville would need electricity.

Using this approach, the Council forecasts Bonneville will have a minimal need for electricity. The average expected need is under 7 average megawatts for the first decade of the forecast and under 28 average megawatts for the second decade.[81] However, those expected loads reflect a range of simulations. Within this range, there are some circumstances where the need could be larger than 60 average megawatts in the first decade and almost 145 average megawatts in the second decade. Seasonally these needs are more likely to occur in the summer, with the upper end of the range of forecast being around 300 average megawatts.

81 Assuming Bonneville customer utilities sign substantially similar contracts.

Section 8: Recommendation for Amount of Power and Resources Bonneville Power Should Acquire to Meet or Reduce the Administrator's Obligation

Resource Recommendations

Energy Efficiency

Public power has played an important role in the Northwest energy efficiency achievements over the last 40 years. Since 2008, Bonneville utility customers have acquired roughly 36 percent of the region's energy efficiency savings. Looking forward, the Council estimates that 36 percent of the remaining available energy efficiency is within the Bonneville utility customer service territories. Bonneville's energy efficiency program will continue to be an important piece of our regional power system infrastructure.

To support both Bonneville's and the regional power system's needs, the Council recommends that Bonneville acquire between 270 and 360 average megawatts of cost-effective energy efficiency by the end of 2027 and at least 865 average megawatts by the end of 2041. Aligning with the Council's analysis of remaining potential and historical achievements, this level represents 36 percent of the overall regional target.[82]

Within the first six years, the Council recommends that Bonneville plan to acquire a minimum of 243 average megawatts of cost-effective efficiency from programmatic savings. This includes savings currently funded through Bonneville's program, whether via the Energy Efficiency Incentive or self-fund utility contributions, as well as the Northwest Energy Efficiency Alliance (NEEA) market transformation initiatives. The remaining efficiency may come through additional programmatic activity, market change, or codes and standards.

Bonneville should use the Council's methodology and associated parameters for cost-effectiveness to identify efficiency opportunities at levels that are cost-effective for the region.[83] This target recognizes the value that Bonneville can provide the region to ensure a reliable power system and achieve decarbonization goals. Additionally, it can mitigate some of the risk associated with potential changes in obligations post-2028 when the current contracts expire.

The Council understands that although Bonneville produces an annual budget, it forecasts its revenues and expenditures on a biennial basis as part of its rate setting process. For the first two years of the 2021 Power Plan, the Council assumes that Bonneville has budgeted appropriately for the agency to successfully achieve the energy efficiency target in this plan. For the remaining years of the 2021 Plan, Bonneville should work with the Council to ensure that a budget is established to successfully meet the plan's energy efficiency targets.

If evaluation of the energy efficiency achievements through the Council's annual Regional Conservation Progress report indicates that Bonneville's achievements fall short of the Council's recommendation, Bonneville and the Council should work cooperatively to understand and address the underlying cause of this shortfall. The Council will continue to work with Bonneville, the NEEA, and the regional utility community to ensure the Regional Conservation Progress report that the Council was directed by Congress to produce annually accurately reflects the regional energy efficiency achievement.

The Council's recommendation for acquiring energy efficiency does not distinguish between energy efficiency

82 The determination of 36 percent as the Bonneville portion of the regional target represents the portion of cost-effective energy efficiency potential located within the Bonneville customer utilities territory. More information on this assessment can be found in the supporting material here: nwcouncil.org/2021powerplan_BPA-CE-Potential-Share

83 The cost-effectiveness methodology can be found here: nwcouncil.org/2021powerplan_cost-effective-methodology

funded through money collected by Bonneville and energy efficiency funded directly by customer utilities. Nor should the Council's recommendation be seen as a recommendation for maintaining or changing the structure of how energy efficiency is funded between Bonneville and its customer utilities. Further, this recommendation is not intended to be proportional to the customer utilities, based on load or potential or any other manner. Our intent is that this recommendation assists individual utilities in determining for their service territory how they can best structure their programs to acquire energy efficiency. Our recommendation is not prescriptive on how individual utilities should run their energy efficiency programs.

The Council recognizes that there are diverse challenges to acquiring energy efficiency across Bonneville's customer utilities. Achieving the efficiency targets will require that Bonneville work to meet each of those utility challenges within the cost-effectiveness considerations. Many of the public utilities with a rural–and primarily residential and agricultural–customer base have fewer energy efficiency opportunities. Additionally, these utilities may lack resources–such as staff, contractors, retailers–and thus have significant challenges implementing cost-effective efficiency programs. To meet its programmatic efficiency goals, Bonneville must work with these utilities and provide territory-wide programmatic opportunities to enhance the infrastructure for small and rural utilities. Continued funding of NEEA initiatives will also provide necessary support for training and other infrastructure to address implementation barriers across its customer utility footprint.

To help ensure the necessary levels of cost-effective conservation are acquired, the Council recommends that Bonneville contribute to all aspects of the regional conservation program, as described in *Section 5: Energy Conservation Program*. This includes continued funding and support in the following areas at levels commensurate with 2020 levels or greater: NEEA; research including regional market research, stock assessments, evaluation, and related analysis; and codes and standards development.

The Council's conservation program also identifies two key opportunities to ensure equitable distribution of energy efficiency. The Council recommends Bonneville continue to invest in weatherization programs, targeting those homes that are leaky (in need of duct or air sealing) and/or have zero or limited insulation. We recognize that these measures, while historically cost-effective, may not be cost-effective under our current paradigm. Nevertheless, the Council believes they are critical to provide livable homes for all people. Bonneville and its customers should consider coordinating with other agencies (such as community action agencies, state agencies, and/or nonprofits) and explore co-funding options to best serve these homes. Additionally, the Council recommends Bonneville work with its utilities with large commercial loads to utilize energy-use intensity data to identify those buildings with significantly higher consumption than comparable buildings. The Council believes leveraging this data will provide a way to identify those commercial consumers in the greatest need of efficiency measures that were previously missed by programs.

Demand Response

In *Section 6: Resource Development Plan,* the Council recommends that utilities pursue demand response that can be frequently deployed and obtained at a low cost. We identified that demand voltage regulation (DVR) and time-of-use (TOU) rates can help substantially in ramping and peak periods. Additional value may also be obtained to relieve transmission constraints and defer transmission and distribution system upgrades.

Bonneville should work to enable and encourage its customer utilities to pursue these and other low-cost and high-value demand response measures in an equitable manner.

Market Purchases

The Council anticipates that regional wholesale electricity prices will have substantial downward pressure from expanded renewable generation additions throughout the West. We recommend that Bonneville, when it has needs beyond the recommended energy efficiency and demand response resources, look to mid-term and long-term market resources for additional energy.

When Bonneville has needs for electricity in specific locations where the ability to deliver power from the federal system is limited, the Council still anticipates the mid-term and long-term market resources will likely be the low-cost resource alternatives.

Renewable Resources

Costs for renewable resources have substantially fallen. While the Council recommends purchasing market resources to meet Bonneville’s needs for additional energy, we recognize that there may be situations where a more general market resource may be more expensive than a direct power purchase agreement, or similar arrangement, tied to a specific renewable resource. The Council recommends that Bonneville compare power purchased in this manner to alternative market products, both in price and capability, to ensure that the lowest-cost product that suffices to meet any need identified is purchased on behalf of the region’s electricity consumers.

Supporting Recommendations

Regional Hydro Generation System

The Council's analysis shows a rapidly shifting market dynamic in the Western electricity grid. The impacts, both challenges and opportunities, need to be better understood and explored by all regional entities that have a role in operating the hydro system.

The Council recommends Bonneville play a central role in these future efforts. Bonneville can do this by both incorporating these impacts into its analyses and supporting broader regional efforts, at the Council and other organizations, to study and understand these impacts.

Future Contracts

The Council's recommendations to the Administrator on what power to acquire depend on the obligation placed on Bonneville. Current contracts allow customer utilities to reduce or abandon service from Bonneville at the end of the contract. Currently all contracts end at the same time, leaving an acute risk that could be aggravated by the Council's recommendations. Our analysis shows the lowest-cost strategy for the Bonneville portfolio changes within the action plan period based on whether regional utilities contract for power from Bonneville in the future.

Further, Bonneville's resource decisions may be limited based on this risk. When all the contracts expire at the same time, decisions made close to the end of the contract period are less likely to favor long-term commitments. This could disadvantage lower cost but longer duration power acquisition.

Bonneville should consider in its next contract negotiations how to mitigate the financial risk of acquiring power that may be least-cost but longer duration. Further, it should explore how a wide range of potential future Council recommendations on resource acquisition could be contractually accommodated without substantial risk of shifting costs among regional consumers of electricity at the end of contract periods.

Additionally, in the current contracts, many Bonneville customer utilities see little value in pursuing demand response and are limited in the ability to provide a demand response resource to another utility, both within and external to the pool of Bonneville customer utilities. In future contracts, Bonneville should consider provisions supporting its customer utilities' development and export of demand response resources.

Section 9: Cost Effective Methodology for Providing Reserves

Reserves in the Act

The Power Act indicates the power plan should include an analysis of reserve and reliability requirements and cost-effective methods of providing reserves designed to ensure adequate electric power at the lowest possible cost. Additionally, the Power Act explicitly recognizes that reserves can come either from generating resources or non-generation alternatives, including conservation measures and contract rights to curtail or interrupt power supplied to customers.

Reserves on the power system are held to account for the uncertainty about the expected amount of electricity demand and power generation. The wholesale power market can help address a significant amount of uncertainty in generation and load. However, most often individual utilities or collections of utilities take actions like holding back some existing resources from the market or adding additional generating resources or non-generation alternatives to address these uncertainties on a second-to-second, hour-to-hour, and year-to-year basis.

Types of Reserves

The growth of electricity demand due to changes in the economy or amount of water available for hydro generation in a year based on precipitation are forecast, but due to the uncertainty of those forecasts, reserve power generation capability is held on a planning basis. These types of reserves are often called planning reserves.

Uncertainty in the forecast speed and direction of the wind hitting turbines or the forecast of households who will have their lights on or air conditioning running at any certain time are examples of shorter-term uncertainties that may cause an imbalance between power scheduled to be delivered to demand. Additional power system capability to meet these schedule imbalances are often referred to as balancing reserves.[84]

While having less fuel uncertainty than solar, wind or hydropower, coal or gas plant generators have the possibility that some aspect of the controlled combustion that creates the power in those plants will go wrong and the entire plant will shut down unexpectedly. Additional power system capability to address these unexpected plant outages are often called contingency reserves.[85]

Since planning for future resource strategies in the power system must explicitly account for these uncertainties, the discussion of the methodology for including reserves in the analytical framework of the resource strategy started with a description of the types of reserves considered: planning, balancing, and contingency reserves. Balancing reserves are held by generating resources that are positioned to ensure that if any errors are made in forecasting load and generation on an hour to hour basis that there is enough of a buffer within the region to make sure generation matches load at all times by increasing or decreasing the amount of electricity being generated.

Contingency reserves are held back to make sure if events like large unexpected forced outages on generators happen that there are enough reserves to match load by increasing electricity generation to replace electricity that becomes unavailable.[86] These operational reserves are part of what makes up planning reserves. The rest of planning reserves account for year-to-year variation in generation and load, such as planning to be able to keep the lights on even during low hydro conditions. All these reserves are incorporated into the calculation of additional resource requirements to maintain the Council's adequacy standard[87] throughout the planning period. The following chart identifies the balancing and contingency reserve requirements that the Council included as inputs into the modeling analysis. The sources of these values are described in the supporting materials.[88]

84 Used maximum of the regional sum of balancing reserves in any hour in the Northwest Power Pool Energy Imbalance Market work as planning assumption for the region.

85 Northwest Power Pool reserve sharing group for contingency reserves

86 Increases in load require increases in generation, called *balancing up reserves* often referenced in the electric industry as *INCs*. Conversely, decreases in load require decreases in generation, called *balancing down reserves* often referenced as *DECs.*

87 5% Loss of Load Probability

88 nwcouncil.org/2021powerplan_reserve-input-assumptions

Operating Reserves

Type	Amount Held
Balancing Up	2,900 megawatts
Balancing Down	3,345 megawatts
Contingency Reserves	3% of load and 3% of generation

Providing Reserves Using New and Existing Resources

Traditionally, additional reserve requirements have more directly translated into needs for additional generating resources, energy efficiency or demand response, but the current analysis indicates that the operations of existing regional generators may play a larger role. In the past, in our region, coal and natural gas generators have complemented regional hydro generation by providing a significant amount of system flexibility. Since the wholesale market electricity price was set by coal or gas generation near times of scarcity, the expectation that those plants would operate if available was a decent assumption.

More Conservative Operation of Existing System to Provide Reserves

In the current and predicted future power system, significant amounts of solar generation throughout the Western grid contributes to very low prices for power midday. These low midday prices can be low enough that coal and gas plants can appear uneconomic to run during the day and plan to shut down to lower overall system cost.

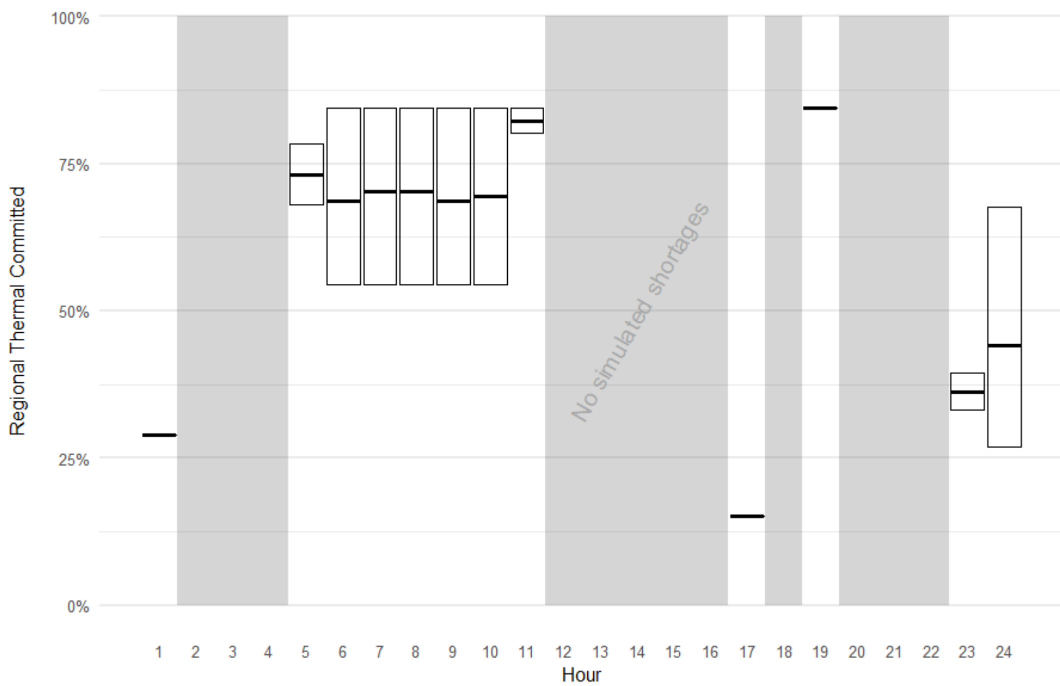
However, when demand for power ramps up in the morning and down at night, there is now significant uncertainty about available generation, along with the uncertainty associated with electricity demand, and that uncertainty introduces some operational challenges.

For example, much of the regional fleet of coal and gas generation need a few hours to ramp up or ramp down from full generation, and fueling larger gas plants requires significant notice ahead of time to order the fuel. Depending on overnight pricing of wholesale power, this could mean that some of these plants might not be seeing an economic signal[89] to stay online or start up with enough time to respond to a potential shortage during those early morning or evening hours where there is significant uncertainty about the amount of electricity demand and generation available.

89 In general, most power plants generate when the cost of producing power is below the price they can receive on the wholesale market for selling power.

These types of operational issues appear to account for almost all the simulated system shortages in the analysis. These issues are not due to a shortage of resources, but in having enough information to operate the existing system economically and adequately.

Maximum Available Thermal Generation During Simulated Shortages[90]



One way to mitigate some of these challenges is to create a signal, in the form of additional reserves, to operate more of these plants to maintain adequacy. This effectively utilizes the existing generators in a way that results in higher overall system cost but less risk of being short generation at a critical time. Plan analysis showed that holding additional reserves overnight does seem to address most of the issues at a slightly higher cost merely by operating the existing system[91] more conservatively.

Additional Resources as a Reserve

Another way to address this issue is to add additional power generation, demand response or energy efficiency. Since reserves are accounted for implicitly in the

90 This graph shows the maximum and average percentage of total thermal generation online during the shortfalls in winter by hour of the day.

91 The existing system providing more reserves is referring mostly to regional hydro, coal and gas generation operated more conservatively

resource strategy analysis,[92] this approach is considered along with all the other reasons to make further investments in the regional power system. Generation resources like wind and solar tend to need more reserves. Generating resources like combined-cycle gas plants have some of the same operational challenges as the existing fleet. Demand response, batteries, and pumped storage can contribute to a solution, but without an explicit reserve signal, are often imperfectly positioned to address adequacy issues. Energy efficiency is the most effective resource at creating more reserve capability in the region; however, it is more expensive than in the past.

Additional Market Reliance

The wholesale electricity market is a valuable tool to take advantage of the diversity of the pool of resources in the Western power grid. Currently, the region has chosen to only rely on resources outside the region on a limited basis (2,500 megawatts per hour in the winter and fall and 1,250 megawatts per hour in the spring and summer). Since Northwest utilities have a limited say in the governance and planning in other regions in the West and due to recent historical events,[93] there has been reluctance on a planning basis to rely more heavily on other region's generation as a hedge against uncertainty, despite the cost advantages.

Cost Effective Reserves as Part of the Resource Strategy

Similar operational issues seen in the analysis have occurred in California power system operations for the last ten years or so, and the market operator in California[94] has multiple strategies[95] to address this issue. One is a more conservative operation of existing system power generators, incentivized by paying extra money to plants with flexibility to stay online. The Pacific Northwest currently has no such market operator,[96] and leveraging off regional collaborations[97] such as the Northwest Power Pool Resource Adequacy effort to achieve a similar mitigation strategy may be advantageous.

92 See Section 6: Resource Development Plan for more details on how these investment decisions are approached.
93 2001 Western Power Crisis
94 California Independent System Operator
95 Market mechanisms to hold more reserves and procure more resources.
96 Other than the limited volume of market trades that are governed within the Western Energy Imbalance market structure
97 Other options include leveraging the current Western Energy Imbalance Market structure and/or further coordinating throughout the West for the day-ahead market via the Enhanced Day-Ahead Market.

Additionally, a slightly more expensive, but effective alternative to this would be to invest more in resources like energy efficiency, beyond what was identified in the resource strategy analysis. A riskier but less expensive mitigation method would be to rely more on the market outside the region.

Major takeaways from the analysis:

1. The least-cost option to maintain an adequate, cost-effective regional system is to couple the investment recommendations (the listed amounts of renewable generation, energy efficiency, and demand response) in the resource development plan with some sort of reserve pooling effort via an organized market or regional collaboration to ensure that sufficient reserves98 can be held to mitigate the increasing uncertainty from increased investment in renewable generation. Part of the reason this method is recommended as the most cost-effective is that the amount of reserves to maintain an adequate system could be changed to match needs over time.

2. A more expensive, but effective, alternative is to invest in more energy efficiency than identified in the resource strategy analysis. This will increase the fixed cost investments required by the region but may be necessary to maintain adequacy should regional coordination to provide additional reserves proves unsuccessful.

3. A less expensive, but riskier alternative is to plan on more external generation to support the region in times of need. Other regions have varying policies, requirements, and Northwest regional stakeholders have less say in their planning processes. Without a more formalized collaborative process like an organized market, this strategy, while taking advantage of the diversity of a large pool of existing resources, would likely expose the region to significantly more risk.

98 Analysis showed that over 3,000 megawatts of additional reserves may be required by 2023 to sufficiently incentivize enough generation to be online in order to have enough fuel to meet morning and evening ramps.

Section 10: Recommendations for Research and Development

The Northwest Power Act directs the Council to include within the plan a "recommendation for research and development." Given the vastly different and rapidly evolving power system, it is important that the Council reflect not only on what we know today, but on what we need to continue to understand to ensure we meet the needs of all the region's consumers. To that end, the Council recommends additional research and development in four key areas:

1. Research to support effective implementation of the conservation program
2. Exploration into alternative approaches to power system operation
3. Research of emerging technologies to support development of future resource options
4. Development of data and tools to enhance future power planning analysis

These recommendations are for entities across the region, with the Council at times providing a supporting role.

Implementing the Conservation Program

The Council is recommending 2,400 average megawatts of energy efficiency be acquired by 2041. Energy efficiency is a slow-building resource. Achieving this goal requires ongoing research to ensure that it is available, reliable, and acquired at the lowest cost.

It requires steady investment to identify opportunities, design programs to deliver efficiency to consumers, evaluate effectiveness, and then refine and repeat. Therefore, the Council recommends that the region continue to invest in research in the areas of evaluation, market research, regional stock assessments, and end-use load research.

In addition to supporting the *Section 5 Energy Conservation Program*, we believe this research provides important insights for identifying demand response opportunities and ensuring effective delivery of those products. The Council recommends the region consider these wider benefits when determining appropriate investment levels for research.

Evaluation

Evaluation is a critical component of understanding the impacts of energy efficiency measures and demand response products. It conveys whether the planned savings were realized, and it can provide insights on how to improve program effectiveness.

Many of the region's efficiency programs–including the Bonneville Power Administration's on behalf of its customer utilities–have robust evaluation efforts. The Council recommends continued investment in energy efficiency evaluation, at levels commensurate with today's investment. This research should include collecting all measure information required to support cost-effective and equitable application of ratepayer funds. Additionally, we recommend that efficiency programs develop evaluations in accordance with the Regional Technical Forum's guidelines, which support consistent and reliable determination of energy efficiency across all measure types.

Market Research

Market research provides thoughtful insights on efficient products available in the market, the availability of contractors and other experts needed to install efficient products (including those with controls that could be used in demand response programs), and where the largest gaps in efficiency adoption exist.

Over the past several years, the region has increased its investment in market research, providing the information needed to refine and focus efficiency programs on the most promising opportunities. NEEA plays a critical role in market research, using its market expertise to take advantage of economies of scale as a regional entity.

Bonneville, the Energy Trust of Oregon, and the region's utility programs also have an important role, particularly in gathering information to address specific local questions or needs. The Council recommends that NEEA, Bonneville, and the region's efficiency programs continue to invest in market research.

Regional Stock Assessments

Through NEEA, regional stock assessments have been conducted that provide snapshots of the existing building stock. This includes information on numbers of buildings, size, use, types of equipment installed, availability of products with controls, and more.

Stock assessments are an important complement to market research, providing another lens for identifying efficiency opportunities and tracking regional progress. The Council recommends that the region's utilities, through NEEA, continue to invest in regular stock assessments for the residential and commercial sectors. Ideally, these would be completed at least once every five years. As part of this effort, NEEA should explore new data techniques for providing more timely information about fast-evolving changes in the stock.

For commercial buildings, the Council recommends that NEEA, with support from Bonneville, Energy Trust of Oregon, and regional utilities, develop a reliable commercial building energy use intensity dataset. The starting point should be the commercial building stock assessment and other publicly available data sources. This dataset will enable efficiency programs to identify buildings that provide the greatest opportunity for significant investment.

The Council also recommends the region's utilities invest in another stock assessment for the industrial sector (including water and wastewater), with particular focus on motors and motor-driven systems. To the extent practical, data gathered on motor and motor-driven systems should also include the agricultural sector, as the region has a long-standing gap of information on this sector. For this work, we recommend that the region build on existing utility data and leverage efficiency program experts knowledgeable with these facilities as a starting point for this assessment.

End Use Load Research

Understanding the timing of energy use, as well as the timing of energy savings, is critical for identifying measures that provide more value for the power system. Today, the region continues to rely heavily on the results from the End-Use Load and Consumer Assessment Program (ELCAP), which was conducted in the late 1980s to characterize the timing of energy use.

Recently, through coordination at NEEA, the region has undertaken a new effort to meter and characterize energy use in residential and commercial buildings. The findings from this research shine light on how we use energy today and provide insights on how new technologies might shift and reduce the timing of energy use.

With the recent Covid-19 pandemic changing how people live and work, this research will answer questions around how energy use has shifted and whether any of those shifts will continue as the new normal. The Council recommends the region continue to fully fund this research and ensure that the knowledge gained is shared broadly for effective investment in all demand-side opportunities. Additionally, the Council recommends that the Regional Technical

Forum use this data to create load shapes for efficiency measures that can be used by the region's utilities to understand the timing of energy efficiency savings.

Exploring Alternative Approaches to Power System Operation

The rapidly decreasing cost of renewable resources, coupled with various state and utility clean policies and emissions goals, are driving large renewable builds across the West. The result: A very different power system. The system requires flexibility, with resource options that can fill in those valleys when renewable energy is not available and support ramping needs when the sun goes down and the lights come on.

Our modeling suggests that we need to rethink power system operations to ensure not only an adequate, efficient, economical, and reliable power supply, but one that continues to protect, mitigate, and enhance the important fish and wildlife in the region. To that end, the Council recommends the region undertake the following explorations aimed at broadening our thinking of power system operation.

Renewable Generation Impacts on Regional Hydropower Operations

The substantial increases in renewable generation across the West shifts power system generation and transforms power markets. The oversupply of renewable generation during the day rapidly shifts to a need for other resources during the evening when the sun is down. Since hydropower has a low variable cost and is flexible, our analysis shows that it is well positioned to help the region absorb increasing renewable generation and ensure adequacy in the region.

However, it is unclear how these daily river flow fluctuations will affect environmental conditions for fish in the river, particularly for juvenile and adult salmon and steelhead migration and for mainstem spawning and rearing habitat. The Council's 2014 Columbia River Basin Fish and Wildlife Program contains measures recommended by the state and tribal fish managers calling on the system operators to minimize or reduce daily flow fluctuations, and yet the analysis suggests a need for increasing fluctuations for adequacy.

The Council intends to organize and support an investigation into the implications of these changing river flows. This effort will bring together Bonneville, system operators, the federal and state fish and wildlife agencies, and the region's tribes. The goal will be to explore the possible benefits and consequences of different hydropower system operations to identify a path forward that provides greater benefit to both power and fish.

Alternative Approaches to Support Renewable Integration

Our analysis suggests other approaches might provide low-cost solutions to support integrating renewables into the existing system. One example is the role of holding reserves. Plan analysis shows that more regional collaboration on holding reserves can provide a lower cost approach to system adequacy.

When a utility holds more reserves, it has more of its existing generation ready if needed to address unexpected loads. Alternatively, with lower reserve amounts, the market prices diluted by the influx of renewables might not provide a sufficient signal to ensure those existing resources are otherwise available if needed. To better understand the tradeoffs around holding more or less reserves, the Council recommends that the region's utilities, regulators, and Bonneville conduct a study to explore how market liquidity by season and time of day can create price barriers for flexible resources, and the cost of mitigating those barriers through greater reserves. This analysis should take into account different hydro conditions.

Another approach to supporting adequacy is demand response. Balancing the system requires that resources are available to quickly meet loads as they come onto the system and can be curtailed as those loads go away. Demand response is a resource that can shift loads away from those high peaks to other times of the day when loads are otherwise low. The Council recommends that Bonneville and utilities research opportunities to use demand response to support system balancing. This effort should provide insight on how to improve modeling these opportunities for future regional and utility power planning efforts.

Transmission and Non-Wires Alternatives

With a potential significant deployment of cheap, new resources vying for access to the transmission system and competing with established, oftentimes more expensive, resources for dispatch to the grid, it is time for the region to reconsider how we contract, reserve, and schedule transmission access.

It is common for a given transmission path to be fully contractually encumbered on a long-term firm basis while still having substantial available physical capacity most or all hours of the year. New resources may face transmission access queues up to several years, creating a barrier to, or slowing, development. While any unused transmission capacity must be marketed for short-term utilization, this can have limited value to project developers who require deliverability guarantees in order to receive financing.

The Council recommends that the region's transmission providers work with utilities, load-serving entities, NorthernGrid, and others to develop a comprehensive review of the existing state of the transmission system; research potential short-term and long-term solutions to alleviate new resource development barriers, while balancing existing long-term contracts and compensation to transmission providers; and explore the potential benefits of implementing a regional transmission operator in the Pacific Northwest.

Additionally, the region should continue to explore non-wires alternatives to address transmission and distribution constraints. Battery storage and targeted demand response, for example, can provide significant value to deferring the need for adding transmission. The Council recommends that the region consider the role of battery storage, targeted demand response, and other demand-side resources to address existing transmission capacity challenges.

This research should speak to the role of these resources in alleviating some of the new resource development described earlier. Additionally, the Council recommends that utilities and Bonneville consider the value of these opportunities on a case-by-case basis to address local needs.

The Council's planning work will require a working knowledge of the impact of new and existing transmission on the region's access to market power and the region's ability to interconnect new generators. The Council is committed to engaging with the region's transmission planners and working alongside them to encourage better coordination on all aspects of long-term planning for the regional power system.

Role of Hydrogen and Fuel Cell Technology

Finally, the 2021 Power Plan is the first to explore the use of hydrogen fuel cell technology as a potential clean energy resource. Hydrogen may be especially promising as a replacement for diesel fuel in heavy duty freight transportation[99] and for some high-heat industrial uses. Currently there is limited demand and production in the region, however this may change in the future with the various clean electricity grid and emission reduction goals.

The Council recommends study of the impacts, benefits, and challenges that large-scale demand and production of hydrogen in the region might have on the power system overall, and in particular, hydro and renewable power. For instance, one hydrogen production method–electrolysis–can be turned on and off, which maybe be useful for balancing load and soaking up excess renewable generation.

99 nwcouncil.org/energy/energy-advisory-committees/demand-forecast-advisory-committee

Emerging Technology

In developing the recommended resource strategy, the Northwest Power Act requires the Council to give priority to resources that are cost-effective. This includes resources that are "reliable and available within the time [they are] needed, and to meet or reduce the electric power demand […] at an estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource."

We recognize that while the resource strategy must focus on those resources available today, there are many potential opportunities that might meet future power system needs at lower costs. To this end, the Council recommends that the region continue to invest in researching emerging opportunities.

As states and utilities progress toward clean, non-carbon emitting energy portfolios, there are opportunities for new, emerging supply-side technologies to compete with established renewable resources–such as onshore wind and solar photovoltaic–and that will play a critical role in the future power system.

The Council recommends that national labs, research institutions, trade allies, and utilities continue to work with developers and manufacturers to research and explore the regional resource potential of supply-side emerging technologies such as offshore wind, small modular nuclear, enhanced geothermal systems, energy storage, carbon sequestration technologies, and other carbon-free resources. In addition, the Council urges the region to identify potential barriers to deployment, including costs, transmission, siting, etc., and work together toward solutions when it is in the best interest of the region.

On the demand-side, new innovations in efficient technologies provide paths to lower cost energy efficiency. To ensure that efficiency measures are readily available and reliable, research is needed to understand the efficacy and applicability of potential technologies.

The Council recommends that efficiency programs, through NEEA, regional universities, national labs, and others should continue to invest in emerging technology research for efficiency measures. This effort includes scanning for emerging technologies, pilot studies to provide case studies for program opportunities, and field research to verify real-world savings.

With less lower cost energy efficiency potential than in prior years, and greater competition with generating resources, this research should also explore opportunities for cost reduction and paths forward that provide the most efficiency benefit at the lowest costs.

The Council also recommends the Regional Technical Forum increase the rigor of its measure cost analysis to support improved comparison with alternative resources in future resource planning. Further, the Council recommends additional research around demand response opportunities.

Our analysis for the plan demonstrates that demand response products that can be frequently deployed at low cost provide significant value to the power system to maintain adequacy and reduce emissions. As utilities and Bonneville explore the value of demand response, the Council recommends that the region continue to develop these non-traditional applications that may provide more value than the standard peak-reducing product.

Development in Support of Future Power Planning

The Council recognizes that power planning is an ongoing effort. The power plan reflects our recommendations based on our understanding of the system today, the availability and costs and benefits of new resources, and existing modeling tools. We recognize, however, that there are enhancements needed to continue to improve our power planning in the future. To that end, the Council recommends developing data and tools in the areas of equity, the valuation of model inputs, and enhanced metrics and tools for improved modeling.

Equity

Through its development of the power plan, and in particular discussions in the System Integration Forum[100] on diversity, equity, and inclusion in the power planning process, the Council identified a gap in equity data that informs equitable representation and accountability in regional and utility resource plans.

The Council recommends that the region convene a series of workshops to investigate existing equity data–encompassing generation, transmission and distribution, and demand-side resources–share publicly available data sources, and perform a gap analysis to identify areas where further research and data are needed.

The goal of this workshop is to develop a regional framework to improve future power planning analysis, including future Council power plans and regional utility integrated resource plans. The workshop participants will need to identify the appropriate entities to manage these efforts long-term. Regional

100 The System Integration Forum brings together multiple Council advisory committees to explore cross-cutting topics. The Forum on diversity, equity, and inclusion was held on February 19, 2021: nwcouncil.org/meeting/sif-2021-power-plan-and-dei-february-19-2021

cooperation and collaboration–broad representation across the region, including many agencies and utility groups–is crucial to the success of this effort. The Council will use its role as convener to assist in launching the first workshop.

Improved Valuation of Model Inputs

Upstream Methane

Despite the focus on renewables, natural gas continues to play an important role in providing energy to the Northwest. Methane, the primary component of natural gas, is an especially potent greenhouse gas, and measures of atmospheric levels have been rising significantly in recent years.[101,102]

The 2021 Power Plan is the first to include an estimate of upstream methane emissions from the natural gas system directly in the planning process. For this plan, the Council–with the expertise of the Natural Gas Advisory Committee–developed an estimate for methane release rate of the natural gas consumed in the Northwest, which is drawn from Western Canada and the Western United States. While we are confident in the approach and assumptions for this analysis, we recognize that there are gaps in our understanding.

Assessing the upstream methane emissions related to the extraction, processing, transportation, and storage of natural gas is a complex undertaking. This has emerged as an important topic, spurring a number of studies that use new methods to assess the overall emissions from natural gas activities in the United States. However, the level of methane releases can vary among specific gas basins. To add a further level of complexity, estimates for the same gas basin can vary depending on the methods and tools that were used to develop the estimate.

The Council recommends working with the Northwest Gas Association and other interested regional bodies to design a study and define a course of action with the goal to more fully quantify the upstream methane emissions related to the natural gas consumed within our region. We also recommend a follow-up study on how best to limit the intended and unintended methane releases related to natural gas consumed in the region.

Valuation of Resilience and Flexibility

Energy efficiency provides values to the power system not readily captured in today's modeling. Two important attributes are resiliency and flexibility. In these terms, resiliency is focused on home and building resilience. For example, some energy efficiency measures provide the ability to ride-through extended power outages or

101 gml.noaa.gov/ccgg/trends_ch4
102 research.noaa.gov/article/ArtMID/587/ArticleID/2742/Despite-pandemic-shutdowns-carbon-dioxide-and-methane-surged-in-2020

extreme weather events. Recent events, like the historic wildfires across the West and the Texas freeze, have demonstrated the importance for home and building resilience during extended outages.

Energy efficiency can also support flexibility. While energy efficiency itself is not a flexible resource, there are many measures that support load management for grid flexibility, whether through integrated control or reducing the impacts on end-users from other load-management efforts.

For both resiliency and flexibility, the Council considered proxy values in the cost-effectiveness valuation to highlight those beneficial measures. The Council recognizes the need to improve this valuation for future efforts. The Council recommends that the Regional Technical Forum investigate methods for quantifying the value of flexibility and resiliency for energy efficiency measures. To ensure symmetrical treatment of energy efficiency with other demand-side and supply-side resources, the Regional Technical Forum should work with other regional experts in developing these values.

Efficacy of Voltage Regulation

The Council recommends that Bonneville, the national labs, NEEA, and regional utilities study the impacts of voltage regulation under current conditions and explore how these results might change with future expected loads.

Utilities may regulate the voltage along the distribution system as a way of changing total energy demand. Reducing the line voltage will reduce the resistive losses in the system, resulting in energy or peak demand savings. The efficacy of voltage regulation is determined by the amount of resistive load on the system. New technological advances and efficiency gains–for example compressor-based equipment replacing electric resistance technologies–have the potential to change the amount of savings from voltage regulation.

Current data for voltage regulation effectiveness are based on older studies that do not represent today's technology mix, nor do they reflect future load sources such as electric vehicles. As the Council and regional utilities base estimates of energy efficiency (conservation voltage regulation or CVR) and demand response (demand voltage regulation or DVR) potential on these studies, updated research will provide more accurate assessments of potential.[103] The analysis for this plan demonstrates the importance of this regulation, particularly DVR as a non-

103 Demand voltage regulation is a product that allows utilities to reduce voltage during peak periods of need and increase it for periods of load building as a way of balancing the system. Alternatively, a consistent reduction in voltage throughout the year can serve as a conservation measure, also known as conservation voltage regulation.

intrusive and regularly available demand response product, for addressing future power system needs.

Valuation of Non-Energy Based Emissions, and Potential Regional Emissions, Sinks, or Offsets

This plan attempts to explore paths toward meeting various economy-wide decarbonization goals. While not in the direct purview of the Council, understanding non-energy sector emissions and viable paths for reducing emissions is important for understanding the interaction between the power sector and these other sources. The Council estimated rough targets in the pathways to decarbonization scenario to explore the tradeoffs between the power sector and other emissions sources in meeting economy-wide emissions goals, but more data would improve future modeling. The Council recommends that the region–including national labs, universities, and state agencies–analyze emissions sources and sinks that may have implications for future power system planning. This data and analysis should be made available to regional stakeholders to support future analysis.

Improved Modeling

Adequacy Metrics for Power Systems With High Renewable Penetration

The Council, and others in the region, have historically used the annual loss of load probability as a measure of power supply adequacy. The changing power system with more prominent seasonal issues requires that the region rethink its assessment of adequacy. Specifically, the Council believes that a set of more detailed adequacy metrics is warranted.

Therefore, the Council recommends that Bonneville and the region's utilities investigate adequacy standards that capture the frequency, duration, and magnitude of potential shortfall events to better understand issues that occur in a system with high renewable generation penetration.

The Council should also investigate underlying system conditions during shortfall events and how adding resources or changing reserves impacts these events. The Council commits to working with Bonneville and the regional utilities on this important issue, with a goal of incorporating improved metrics into future power planning.

Broaden Regional Extreme Event Analysis

In addition to working on how adequacy is assessed, it is important for the region to understand the impact of extreme events on the power system. Major heat waves and cold spells in the Northwest and across the country have emphasized the need for investigation and utility cooperation in estimating the impact and frequency of such events.

The Council recommends that Bonneville and regional utilities, working with the

Council, coordinate in developing methods to estimate their frequency, magnitude, and duration. Further, the Council recommends adapting these methods to allow investigating their impact in the full range of power system models, including those used by the Council in its power planning processes.

Revisit Analytical Approaches to Planning for the Electric System

The models and analytical approaches used by the Council and regional utilities for power planning reflect standard industry practice. These standard industry practices are based on a historic electric system that is different than our present-day electric grid. Furthermore, we expect a substantial transformation of the grid that will diverge even more from the electric system these models and approaches were designed to simulate.

While the timing and extent of this transformation is unclear, the Council recommends the region, including national labs, universities, and other experts, research how effective the current models are at forecasting or simulating system operation and at projecting the future drivers of electricity demand. This research should focus on production-cost models, load-forecasting models, and capacity-expansion models.

Production-cost models, the computer programs most often used to estimate electricity prices, use the marginal pricing theory from economics, which in the current electric system means electricity prices are largely forecast and formed based on what it costs to operate fossil-fuel-based generation.

However, fossil-fuel-fired generation is rapidly being retired and will likely make up a smaller portion of the future electric system. With fewer fossil-fuel power plants in the system there will be fewer power plants ready to respond to market prices and more generators that have minimal or even negative operating costs, such as wind and solar plants.

This shift in generation results in prices being more volatile, likely leading to inefficiencies in the market and possibly a breakdown in the economic theory on how electricity market prices are formed. This impacts the accuracy and efficacy of widely used production-cost models. Since forecasting future electricity prices is fundamental to the Council's analysis, we recommend the next generation of production-cost models directly address this challenge.

In load-forecasting models, we have made progress toward incorporating climate change into our analysis but would also encourage a broader regional conversation on methods that adapt our forecasts to a changing climate. We also see that future demand for electricity depends on the interaction of the electric system with purposes that have historically been served by other forms of energy, such as electric vehicles replacing those previously powered by gasoline.

The interaction between the different forms of energy used in our region or in the broader Western electric grid could have wide-ranging impacts on our future power plans. In this plan, we have shown the range of potential future electric loads is extremely large, depending on the extent of electrification of transportation and buildings that occurs. We recommend the next generation of load-forecasting models focus on improving estimates of these interactive effects.

Capacity-expansion models generally assume a static demand for electricity is met by adding differing types of generating technologies, while minimizing the capital cost and fixed and variable costs of operating the resulting system. The next generation of capacity-expansion models will likely need to assess trade-offs between different technologies on the demand-side, particularly hydrogen produced by electrolysis, an energy-intensive process.

Also, in using models to test capacity expansion, it's important to capture the impacts on the existing system from dynamically adjusting reserves and storage deployment for different generating technologies. Finally, capacity-expansion models are computationally intensive, therefore we recommend that future models focus on those questions that result in a meaningful difference, recognizing that these may be different questions than in the past.

The Council recommends that analysis of the current generation of models should both address these concerns and explore further implications of how transformation of the electric system will affect our ability to appropriately capture future risks and requirements for power planning.

Section 11: Methodology for Determining Quantifiable Environmental Costs and Benefits and Due Consideration for Environmental Quality, Fish and Wildlife, and Compatibility with the Existing Regional Power System

The production, generation, and distribution of electricity affects the environment, and environmental effects will vary based on several factors, including the resource type and technology, fuel use and extraction processes, the facility size and footprint, and location. Pursuant to the Northwest Power Act, in its power planning, the Council must consider environmental effects related to the power system and integrate these considerations into its analysis through various statutory vehicles. For example, perhaps reflecting the time when the Act was drafted, when natural resource policymaking shifted to recognize the importance of internalizing environmental externalities, Section 4(e)(3)(C) of the Act requires the Council to include as an element of the power plan a “methodology for determining [the] quantifiable environmental cost and benefits” of new generating and conservation resources.

Further, Section 4(e)(1) of the Northwest Power Act requires that the Council’s regional power plan give “priority to resources which the Council determines to be cost-effective.” The definition of cost-effective, found in Section 3(4) of the Act, requires that the Council estimate and compare the incremental system costs of different generating and conservation resources, with system cost defined as:

> “an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, the cost of distribution and transmission to the consumer and, among other factors, waste disposal costs, end-of-cycle costs, and fuel costs (including projected increases), and *such quantifiable environmental costs and benefits as the Administrator determines, on the basis of a methodology developed by the Council as part of the plan, or in the absence of the plan by the Administrator, are directly attributable to such measure or resource.”*

Consequently, the methodology for determining environmental costs and benefits not only represents one of the vehicles available to the Council to analyze and integrate environmental effects into its planning, it is also a significant component of the Council’s work to estimate and compare the system costs of a particular resource and ultimately determine those resources that are most cost-effective for the region.

In addition, Section 4(e)(2) of the Act requires that the Council set forth a general scheme for implementing conservation measures and developing resources with due consideration for, among other things, environmental quality, and the protection, mitigation and enhancement of fish and wildlife. Therefore, this statutory vehicle introduces a broader set of environmental considerations for the Council to deliberate on as it analyzes new generating and conservation resources, and, importantly, as it assembles those new resources into a regional resource strategy.

The first part of this section describes the Council’s methodology for determining environmental costs and benefits for the 2021 Power Plan. Implementation of this methodology is then reflected in the resource strategy discussed in Section 6, with the supporting materials providing additional analysis regarding the resource cost assumptions and analysis (See the methodology for determining quantifiable environmental costs and benefits section of the new generating resources supporting materials and the cost and benefits of energy efficiency supporting materials).

The second half of this section describes how the Council, in developing its resource scheme, gave due consideration for environmental quality, compatibility with the existing regional power system, protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish, and other criteria as set forth in this plan. This last part of the section, describing how the Council gave due consideration to each of these listed factors, captures how the Council grappled with and used these considerations to shape its final resource strategy and planning decisions.

Methodology for Determining Quantifiable Environmental Costs and Benefits

Section 4(e)(3)(C) requires the Council develop and include as an element of the power plan "a methodology for determining quantifiable environmental costs and benefits" of new generating and conservation resources.

The Act does not prescribe a particular procedure or method that the Council must undertake in developing its methodology. However, the sum of the provisions of the Act addressing the methodology, Section 4(e)(3)(C) and Section 3(4)(B), are specific in that the methodology is to consider costs and benefits to the *environment*, not to any other type or category of costs and benefits, and that those environmental costs and benefits must be *quantifiable* and *directly attributable* to the new resource. These terms, "environmental," "directly attributable," and "quantifiable," are not defined in the Act; therefore, the Council has used a common-sense understanding of the terms, guided by the context in the Act, discussions included in the legislative history, and at times, the Council has exercised its judgment on a reasoned basis in making determinations as to what these terms mean and how they apply for purposes of the methodology.

For the 2021 Power Plan, and consistent with previous plans, the Council has identified four primary components to serve as the base of the methodology: 1) compliance with existing regulations; 2) environmental effects beyond regulatory controls, including both residual and unregulated; 3) compliance with proposed environmental regulations; and, 4) environmental benefits.

Each component is discussed in detail below. However, before discussing each component, it should be understood that Section 3(4)(B) of the Act requires a back and forth between the Council and the Bonneville Power Administration's administrator to develop and then apply the methodology that is not workable in practice for development of the power plan. Under the precise language of the Act, as part of the plan, the Council must develop a methodology for determining quantifiable environmental costs and benefits, then on the basis of that methodology, Bonneville's administrator is to determine such quantifiable environmental costs and benefits directly attributable to each resource, and then the Council is to incorporate the administrator's determinations into the estimated system cost of each new measure or resource to determine the cost-effective resource strategy for the power plan.

Following this specific direction does not work, as the Council cannot issue a power plan that includes the cost-effective resource strategy without first estimating and comparing the resource system costs, which requires considering quantifiable environmental costs and benefits. To make these provisions work together, the Council provides Bonneville, and others, including various advisory committees, the opportunity to examine and comment on the Council's methodology and the environmental costs and benefits attributed to each resource both prior to and following issuance of the draft plan. Any concerns identified in comments on the draft plan will be considered and addressed in the final plan.

Components of the Methodology

Cost of Compliance with Existing Regulations

The Council's planning assumes that all new (and existing) generating and conservation resources will comply with existing federal, state, tribal, and local environmental regulations. This includes, for example, compliance with environmental regulations governing air and water emissions, siting and licensing, waste disposal, fuel use (extraction and production), and fish and wildlife protection and mitigation requirements.

Existing regulations reflect policy decisions already agreed upon regarding the environmental costs and the appropriate level of protections to redress that harm, the costs are directly attributable to the resource, and largely quantifiable as a component of capital installment costs and fixed and operating costs.

Therefore, the estimated cost of compliance with existing environmental regulations is the primary method the Council has used to quantify environmental costs of generating and conservation resources in past plans, and it is again the primary method for the 2021 Power Plan.

While the cost of compliance may seem most obvious for generating resources, the costs of compliance also factor into the total system cost of new conservation measures, to the extent there are applicable environmental compliance costs quantifiable and directly attributable to the measure.

The generating resource reference plant section of the new generating resource supporting materials describes the environmental effects of generating resources, with existing systems and policies supporting materials providing additional information on the environmental effects of generating resources and outlining the existing environmental regulations to address those effects.

In addition, the methodology for determining quantifiable environmental costs and benefits section of the new generating resources supporting materials and the cost and benefits of energy efficiency supporting materials, describe and assess resource system costs, including costs of compliance. The supporting materials for the methodology also expound on how the Council applies this method using an existing regulation as an example.

Cost of Compliance with Proposed Environmental Regulations

The Council has typically dealt with the cost of compliance with proposed environmental regulations on a case-by-case basis depending on the proposal, the effects the proposal addresses, and the quantitative data available. The Council is again deciding to address costs of compliance with proposed regulations on a case-by-case basis for the 2021 Power Plan. However, at the time of drafting this plan, there were no environmental regulations proposed that set stricter standards than those previously established for new resources. Consequently, there were no costs of compliance with proposed regulations added to any new resource system costs.

Environmental Effects Beyond Regulatory Controls

Existing environmental regulations control or mitigate for some amount of the targeted environmental effects from generating or conservation resources, but existing regulations do not control or mitigate for all environmental effects of resources–including residual. Residual effects remain after compliance with current regulations. For example, not all discharges from an electric generating facility, whether to the air or water, are controlled or prevented by the limitations and standards established pursuant to the Clean Water Act or the Clean Air Act, nor are all bird kills from wind turbines prevented by current regulations.

In addition, there are unregulated effects, which are environmental effects not yet regulated or not currently under regulation. The social cost of carbon emissions is an example of an associated environmental effect of a resource that is currently beyond regulation.

The Council acknowledges there are environmental effects beyond regulatory control that should be considered in the Council's planning. However, quantifying costs for these effects in a resource's system cost is difficult, if not impossible, due to the persistent lack of adequate data and methods to determine reasonable quantitative costs.

Moreover, while sufficient data is available for a few effects (e.g., the social cost of carbon) data largely remains deficient for most other residual or unregulated environmental effects. Adding the determined costs of some effects to some resource costs, but not the costs of all known effects to all resources due to an inability to reasonably quantify them could lead to an inappropriately skewed resource cost comparison.

Further, when estimating and comparing resource system costs, it is most useful for the Council to consider costs reasonably anticipated or appropriate to be borne by the power system. Considering social or damage costs in the direct costs of a few resources could lead to potentially applying costs to some resources that are extraneous to the power system, resulting in inconsistent resource cost comparisons.

Therefore, consistent with previous power plans, for the 2021 Power Plan, the Council is continuing to acknowledge and examine residual and unregulated effects qualitatively in the resource analysis and in developing the resource strategy because it remains infeasible for the Council to develop quantitative cost estimates for these effects, especially in a systematic or consistent way across resources, and then add them to the new resource system costs.

The methodology supporting materials provides additional detail regarding the data insufficiency and the hinderance it presents to the Council in estimating the costs of these environmental effects beyond regulation. The Council's qualitative assessment of these effects is described in the generating resource reference plant section of the new generating resource supporting materials, with the environmental effects of generating resources found in the existing systems and policies supporting materials providing additional information.

The Council integrates environmental effects into its power planning, and considers unregulated environmental damages, through the lens of Section 4(e)(2)–the provision requiring that the Council give due consideration to, among other factors, environmental quality and the protection and mitigation of fish and wildlife.

A prime example of this is the continued implementation of protected areas. Protected areas were first adopted by the Council in 1988 as an element of the Council's fish and wildlife program. They are river reaches where the Council believes new hydroelectric facilities would have unacceptable risks of loss to fish and wildlife species of concern or their habitat.

Their designation, and continued implementation and enforcement, is an explicit expression of the Council's due consideration of the effects of new energy resources on environmental quality and fish and wildlife resources.

In the power plan, the Council has included the social cost of carbon from the Intergovernmental Panel on Climate Change as part of the portfolio cost calculation, with upstream methane emissions factored into that cost calculation as well. While these environmental effects are not added as a direct cost of the resource via the methodology, these effects are considered and integrated into the Council's planning, and their impact is reflected in the Council's resource decisions detailed in the resource strategy (Section 6).

For additional details regarding how the social cost of carbon was incorporated into the Council's planning including in scenario analysis and as one component of the net present value of the total portfolio cost in the regional portfolio model, see the Global Assumptions[104] in the supporting materials

Quantifiable Environmental Benefits

In addition to quantifiable environmental costs, the Act also requires the methodology address quantifiable environmental benefits of new generating and conservation resources. When considering environmental benefits, a key issue for the Council is whether and how to factor into the system cost of a new resource the benefit of being able to reduce an existing activity that has an environmental cost.

The Council acknowledges that the environmental benefit of a resource should be recognized and considered within the resource analysis in some capacity. However, the question for the Council is whether these environmental benefits can be quantified and determined to be directly attributable to the new resource. The Council is deciding to not attempt to include quantified environmental benefits in new resource costs beyond a few historic examples and will instead emphasize in the resource strategy how certain resource choices help to mitigate harmful environmental effects.

Except for a few minor exceptions, the Council has not been able to quantify environmental benefits of new resources because information and data on environmental benefits is not available,

104 nwcouncil.org/2021powerplan_global-assumptions-power-plan

sufficient, or well understood. Quantifying financial aspects of reducing environmental harm is also often missing or quite speculative in the data that is available.

It is also difficult to determine that a reduction in environmental harm (or an environmental benefit) is directly attributable to the new resource and not simply incidental or indirect. And, as noted earlier regarding the effects beyond regulatory control, while it may be possible to capture quantified environmental benefits for a few resources, the Council is reluctant to engage in a piecemeal quantification of benefits, which could result in a skewed resource cost comparison.

To use a familiar example, installing an efficient washing machine saves energy and reduces water consumption, which is an environmental benefit. The reduction in water consumption is a direct benefit of installing the efficient clothes washer and the Council is able to quantify this direct environmental benefit by utilizing consumer water and wastewater bills as data to support the quantification.

The Council can do a similar analysis for other water-saving measures, such as dishwashers, showerheads, and aerators. However, to walk through another familiar example, installing a ductless heat pump in the main living area of a house may result in burning less wood. With less wood burned, particulate emissions are reduced, which is a benefit to the environment (air quality) as well as a benefit to human health.

However, in this example, it is more challenging for the Council to say whether the environmental benefit (reduced particulate emissions) is directly attributable to the installation of the ductless heat pump, or a result of a behavior choice and incidental to the installation of the measure. Also, this environmental benefit is more difficult to reasonably quantify due to a lack of appropriate data and tools for quantification. Therefore, the Council has not added this benefit to the cost of the measure.

Since the Seventh Power Plan, more information on quantifying environmental benefits has been developed, but not enough to enable the Council to quantify environmental benefits to a broader degree. Specifically, the U.S. Environmental Protection Agency issued a report in July 2019, *Public Health Benefits per kWh of Energy Efficiency and Renewable Energy in the United States: A Technical Report,* addressing the public health benefits associated with conservation and renewable resources, and Washington investor-owned utilities (IOU) issued studies analyzing how to monetize the benefits of reduced wood smoke from the installation of ductless heat pumps. The Washington IOU studies did provide new location-specific information for quantifying the environmental benefits of reduced wood smoke. However, they do not resolve the

Council's concerns since it's difficult to say to what extent reductions in particulate emissions are directly attributable to the installation of the efficiency measure. And, this additional data does not address lingering concerns regarding piecemeal quantification leading to a skewed resource cost comparison.

To be clear, the Council recognizes that particulate emissions from wood burning are a well-documented health concern, and the installation of a new electrical measure in the right circumstances may lead to reduced emissions. The Council will continue to exercise its discretion on the basis of the data currently available and not apply these benefits to the cost of new conservation resources. Nonetheless, state and local government, regulatory commissions, and utilities are more than justified in continuing to pursue these measures based on the health and societal benefits.

The EPA's report recognized energy efficiency and renewable resources reduce emissions. The report quantified near-term benefits of reduced emissions using avoided emissions rates based on 2017 electricity generation, which resulted in dollars per kilowatt values for conservation and renewable resources.

EPA advised, however, that the values should not be used to estimate benefits beyond 2022 given the emission rates underpinning the values.[105] Thus, capturing these benefits in new resource system costs for the 2021 Power Plan, would require significant analysis by staff to extend the values through the 20-year planning period.

More importantly, however, is the transformation occurring in the region and broader Western electric grid as significant amounts of renewable resources are added. This is spurred by lower resource costs, coal retirements, and clean energy policies. Emissions will be changing over the next five to 10 years and beyond; with increased reliance on zero-emitting resources, the avoided emissions rate for the region will also be changing.

This will lead to an even lower dollars-per-kilowatt-hour benefit in future years. The potential for the benefit value to become less significant over the course of the planning period compounds the Council's concerns regarding: 1) applying these benefits piecemeal; and 2) the risk of inappropriately skewing the resource cost comparison.

Moreover, there are other vehicles under the Act enabling the Council to consider the environmental effects of resources; one is its due consideration of environmental quality. In developing the power plan, the Council considered greenhouse gas emissions, as well as climate change, and integrated each of these into its analysis. Climate change

105 EPA issued an update to the 2019 report in May 2021. However, data for the 2021 Power Plan was frozen in April 2020; moreover, the May 2021 update recommends its values not be used beyond 2024.

mpacts on temperature and precipitation, which affect loads and river flows, were integrated throughout our quantitative analysis and modeling, and the Council included the social cost of carbon from the Intergovernmental Panel on Climate Change as part of the portfolio cost calculation in the regional portfolio model, with upstream methane emissions factored into that cost calculation as well.

While the environmental effects of carbon were not added as a direct cost or benefit of a new resource via the methodology, its effects were considered and integrated into the Council's planning, and the impact of that consideration is reflected in the Council's resource decisions, addressed in more detail below. Additional Information on how the social cost of carbon was incorporated into the power planning analysis is in the Global Assumptions[106] in the supporting materials.

Therefore, for these reasons and consistent with the Council's previous application in past power plans, the Council did not attempt to include quantified environmental benefits in new resource costs beyond the few historic examples, and instead recognizes and emphasizes in the resource analysis the value of certain resource choices to help mitigate other harmful environmental effects.

See the methodology for determining quantifiable environmental costs and benefits section of the new generating resources supporting materials and the cost and benefits of energy efficiency supporting materials for additional information on benefits included in resource system costs. And the generating resource reference plant section of the new generating resource supporting materials describes the environmental effects of generating resources, with existing systems and policies supporting materials providing additional information regarding the environmental effects of generating resources.

Due Consideration for Environmental Quality, Fish and Wildlife Protection, Mitigation and Enhancement, and Compatibility with the Existing Regional Power System

The Power Act calls on the Council to develop the conservation and generation resource strategy for the plan "with due consideration by the Council for (A) environmental quality, (B) compatibility with the existing regional power system, (C) protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat,

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including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish, and (D) other criteria which may be set forth in the plan."

The following documents how the Council provided "due consideration" for these matters in developing this Power Plan, with particular focus on considerations of environmental quality and fish and wildlife. There are certain matters the Council considers with every power plan that are relevant here, and other matters particular to this plan. Both are highlighted as follows:

Fish and Wildlife Program; Hydropower System Operations for Fish and Wildlife

The Act requires the Council to call for recommendations and amend the fish and wildlife program prior to the power plan. The Act then makes the fish and wildlife program a mandatory element of the power plan. See *Section 12: Fish and Wildlife Program.*

One of the reasons for this is so that the Council, in developing the power plan, can assess how dam operations to benefit fish affects hydropower generation, both in its amount and timing, and then design a regional resource strategy that accounts for any reduction in generation available.. The Council designs the strategy in part to facilitate reliable implementation of the system operations for fish, while continuing to assure the region an adequate, efficient, economical, and reliable power supply.

The Council's analytical models and scenario analyses for the power plan incorporated all the latest system operations recognized in the Council's fish and wildlife program. This includes reservoir operations, spill, and other passage operations, including the flexible spill operation for juvenile fish incorporated into the program from decisions external to the program, such as the most recent Columbia system biological opinions. These operations are all incorporated into the Council's modeling and analytical work on the scenarios, as well as the baseline conditions. The Council's resource strategy is developed in part to assure an adequate and reliable power supply that will also allow for reliable implementation of fish operations.[107]

107 In October 2021, after the Council published the draft power plan for public review and comment, the federal agencies operating the Columbia River System agreed to a slightly different set of spill and run-of-river reservoir operations for 2022, for one year only.
See: pweb.crohms.org/tmt/JointMotion_TermSheet_CourtOrder_OCT2021.pdf. Although a formal analysis is not available, Bonneville Power Administration staff publicly reported its estimate that the operations agreement for 2022 would reduce the federal system's average hydro output approximately 45 aMW compared to the operations that were to occur in 2022, as specified in the 2020 Columbia system biological opinion. See: newsdata.com/nw_fishletter/bpa-estimates-power-impact-of-additional-spill-in-agreement/article_5b341294-56c6-11ec-9028-e702aac7ae67.html. The Council decided for the final power plan not to revise the operations in

Environmental Effects From the Generation of Electricity and Conservation

The Council identifies the various environmental effects from the generation of electricity in all phases of the life cycle of a new generation resource. They include, for example, the effects on land, water, habitat, and fish and wildlife during construction; environmental effects of key parts in manufacturing; fuel development and transportation; operational effects, such as air and water emissions or harm to wildlife or fish; waste disposal; and end-of-life decommissioning and similar matters. The Council also identifies environmental effects to the extent possible for conservation measures and other non-generation alternatives.

The Council described these effects in a comprehensive way for the Seventh Power Plan, especially in Appendix I. The Council reviewed and updated this information as necessary for the 2021 Power Plan. See the supplemental material for generating resources, especially the discussion of environmental effects in the generating resource reference plant section and the environmental effects of generating resources.

To the extent these environmental effects can be quantified in dollar terms, the Council includes these resource costs for the new resource cost comparison, as part of in the environmental cost and benefit methodology described above. Environmental effects and damage that cannot be quantified in the same way are still recognized and considered in developing the resource strategy.

Unquantifiable environmental impacts and damage from utility-scale generating developments have always been an additional consideration for implementing conservation measures and for other power system efforts that avoid construction and operation of major facilities, including demand response measures, and in certain cases, more efficient use of existing generation facilities.

Protected Areas

Beginning in 1988, the Council adopted protected areas as an element of the Council's fish and wildlife program and power plans. In these provisions, the Council calls on the Federal Energy Regulatory Commission (FERC) to not license a new hydroelectric project in river reaches with valuable fish or wildlife resources that the Council identified and mapped in a protected areas database by the Council. The protected areas provisions also call on Bonneville to not acquire the output of, or provide transmission support for, such a project, assuming it were to receive a license. To date, FERC has not licensed a new hydroelectric

the baseline conditions and re-run the model analyses for all the scenarios. The size and duration of the change in generation is not of a magnitude to affect the resource strategy.

project in a protected area identified by the Council.

In the power plan context, protected areas represent a judgment by the Council that due to potential effects on habitat, flows, and passage, the adverse effects on, and environmental costs to, important fish and wildlife resources are too great to justify including new hydroelectric projects in these areas, except under certain limited conditions.

The existing power system is already bearing substantial costs to protect and mitigate for its impacts on fish and wildlife resources. The power plan context is also important in that the protected areas designation extends throughout the entire Pacific Northwest (essentially the same as the Bonneville service territory), not just within the Columbia River Basin. This is part of the resource strategy for the region's power system, as well as a comprehensive plan for the region's waterways and new hydroelectric development.

As the Council evaluates the potential and cost-effectiveness for new hydroelectric development in each power plan, it includes the effects of protected areas in limiting the extent of that potential. The Council also gives due consideration to fish and wildlife and the quality of their environment by including a set of development conditions to protect fish and wildlife as new hydroelectric projects are licensed and developed in areas outside of the protected areas.

Greenhouse Gas Emissions and Climate Change

The environmental quality topic of primary interest in this plan, as in the last two, was the issue of greenhouse gas emissions and climate change. The Council has considered this topic in several ways in formulating the plan's resource strategy, including:

- The Council closely tracked state and other legal and policy developments in the region and across the West that require retiring, or reduced emissions from, coal-fired generation; the scheduled retirements of coal plants; the addition of renewable resources through renewable portfolio standards; and clean energy standards and greenhouse gas reduction goals from the electrical power system. The Council designed a resource strategy for a power system consistent with the effects of these laws, policies, and commitments. Part of the Council's aim in the power plan is to help the region understand a least-cost way to make this transition and retain an adequate and reliable system.
- The Council included greenhouse gas emissions considerations in new resource costs whenever possible to quantify and also tracked emissions effects to the extent possible. This includes upstream

methane emissions from natural gas production.

- The Council also integrated climate change effects into the baseline conditions and analyses, including climate change impacts on river flows for hydropower generation and on loads from changing temperatures.
- The Council included a cost of carbon in the baseline analyses as a damage cost on emissions from existing and new fossil-fueled generation. The Council also ran several scenarios or variants to test different aspects of this issue – removing the social cost of carbon; accelerating the retirement of coal plants; restricting the build of renewable resources; restricting the build of new natural gas plants; assessing the emissions reduction effects of a demand response sensitivity case; assessing in several different ways the power system effects of an economy-wide effort to decarbonize; and more. One result tracked for all model analyses was the resulting change in system emissions of greenhouse gases.

More details on how the Council considered this topic can be found in several different sections of the plan and supporting materials, including the resource development plan, the global assumptions in the power plan, the generating resource reference plants, and environmental effects of generating resources.

Protecting Environmental and Cultural Resources From the Impacts of New Generating Resource Development

The siting, construction, and operation of any generating facility has impacts on land uses; water resources; wildlife and wildlife habitat conditions; cultural resources; traditional uses; and local landowners and communities.

Environmental effects of any proposed development are analyzed as part of state energy siting processes (if on private land) or by state or federal land management agencies (if on public land) through an array of different criteria and procedures. State fish and wildlife agencies and tribes have commented throughout the last two the power planning processes, sharing concerns that energy siting decisions for renewable facilities are not or may not be as protective of wildlife, habitat, cultural resources, and traditional uses as optimally needed. As the scale of development increases, so do concerns about the impact of a host of individual decisions and about the cumulative impacts.

The Council's Fish and Wildlife Program has a set of standards and conditions for developing new hydroelectric projects outside of protected areas. The purpose is to "ensure that new hydroelectric development is carried out in a manner that protects the remaining fish and wildlife resources of the Columbia River Basin and the Pacific

Northwest and does not add to the region's and ratepayers' mitigation obligation."

The Council has been asked to consider including in the power plan a similar set of development conditions for renewable resources. While siting authorities have no obligations to the Council's power plan, unlike the Federal Energy Regulatory Commission and hydroelectric project licensing, the Council commits to working with stakeholders throughout the region to help guide the consideration of aggregated effects of new renewable resources.

The Council also recommends that siting authorities should work to ensure that new renewable resource development is carried out in a manner that protects wildlife and fish and cultural resources of the Pacific Northwest.

The emphasis should be to incorporate "least impact, less conflict" siting principles to push development away from high value lands; ensure deliberate, strategic outreach and engagement in siting processes with fish and wildlife agencies and tribes and communities directly affected by development; and ensure that tribes are consulted to understand and preserve cultural resources and traditional uses in the vicinity of developments.

Hydrosystem Flexibility and Possible Impacts to Fish

The substantial increases in renewable generation across the West shift power system generation and transform power markets. The increasing supply of solar generation during the day highlights the need for other resources when the sun goes down.

Since hydropower has a low variable cost and is flexible in its use (within certain established parameters noted earlier), the Council's analyses – and current actual practice – indicates that the hydropower system is well positioned to help the region absorb increasing renewable generation and ensure adequacy in the region.

However, it's unclear how these daily river flow fluctuations – which are already evident and will likely increase if power considerations drive river operations - will affect environmental conditions for fish, particularly for juvenile and adult salmon and steelhead migration and for mainstem spawning and rearing habitat.

The Council's 2014 Columbia River Basin Fish and Wildlife Program contains measures recommended by the state and tribal fish managers calling on system operators to minimize or reduce daily flow fluctuations, and yet the power system analyses indicate a system adequacy benefit from increasing generation and flow fluctuations.

As described in the research recommendations in *Section 10: Recommendations for Research and Development*, the Council intends to organize and support an investigation into the implications of these changing river flows. This effort will bring together the Council, Bonneville, system operators, the federal and state fish and wildlife agencies, the region's tribes, and others. The goal will be to explore the possible benefits and consequences of different hydropower system operations to try to identify a path forward that provides greater benefit to both power and fish.

Compatibility with Existing Power System: Retirement of Existing Coal Plants; Lower Snake River Dams

The Council's power plan, under the Northwest Power Act, is to analyze and recommend what new conservation and generation resources should be added to the region's power supply. The Council is to do so while taking into consideration not just matters of environmental quality and fish and wildlife impacts, but also the compatibility of new resources "with the existing regional power system."

The Council has done so in several ways, including analyzing how existing hydropower and gas plants have a valuable role in integrating additional significant amounts of renewable resources in a cost-effective manner while preserving an adequate system.

The Council's task is not to analyze or decide whether elements of the current system should remain or be retired for environmental or economic or other reasons. The Council does need to consider decisions made by others to retire or reduce the output of existing resources or constrain what types of new resources may be added.

This includes, for this power plan, the current set of decisions by utilities to retire coal-fired generating units for reasons of economics and state law, as well as the new state laws requiring the addition of renewable or clean resources, both part of a policy effort to reduce the output of greenhouse gas emissions from the existing system.

In this instance, the Council needs to analyze the effects of those plant retirements on the existing power system and decide what resources, and in what amounts, need to be added to assure the region retains an adequate, efficient, economical, and reliable power supply.

In this plan period, numerous comments have been submitted asking the Council to analyze or recommend the removal of the four federal dams on the lower Snake River. There are no planned retirement dates for any mainstem dams on the Snake and Columbia. So, the Act does not require that the Council analyze the effects of the retirement of those plants for this power plan in order to develop the power plan's new resource strategy and fit that strategy to the existing if changing power system. And it is not the Council's task under the Act, in the power planning process, to analyze or recommend the retirement of existing system resources.

However, there may be value to the region, following the completion of the power plan, in analyzing the power system effects if the output of the dams were no longer available sometime in the future, including what replacement resources would be needed to achieve similar levels of reliability. The Council will begin scoping and considering whether to undertake this analysis after the plan is adopted.

Section 12: Fish and Wildlife Program

The Council's *Columbia River Basin Fish and Wildlife Program* is one of the required elements of the power plan under the Northwest Power Act. The 2014 Fish and Wildlife Program, supplemented by a 2020 Addendum, is the Council's current version of the program. nwcouncil.org/reports/2014-columbia-river-basin-fish-and-wildlife-program

The Act requires the Council, prior to the review of the power plan, to call for recommendations to amend the fish and wildlife program and then follow the process described in the Act for deciding on program amendments. The Council did so, initiating a fish and wildlife program amendment process in 2018 that culminated in a final decision on the 2020 Addendum to the existing program toward the end of 2020. Section 11 includes a discussion of the role of the fish and wildlife program in the development of the 2021 Power Plan, as part of the required fish and wildlife and environmental considerations.

The Council's fish and wildlife program has evolved through time. Early programs focused largely on improving juvenile and adult fish survival at and through the mainstem Columbia and Snake river dams, including water management and fish passage provisions for anadromous fish and reservoir operations to benefit resident fish. Early program developments also included anadromous fish loss assessments and systemwide goals; wildlife loss assessments and the beginning of mitigation for those losses; and the designation of protected areas to protect the region's fish and wildlife resources from new hydroelectric development.

Over time, the Council built up other portions of the program, especially expanding the off-site mitigation activities of the program with habitat improvements and fish hatcheries in the tributaries off the mainstem and in the lower Columbia River and estuary.

The 2014 Program reflects work built over many years of program development and implementation, with a continued emphasis on mainstem water management, passage improvements and spill, and offsite habitat and hatchery mitigation improvements.

The 2014 Program also identified a set of emerging priorities and called on Bonneville, the other federal agencies, and the region to integrate these emerging priorities into program implementation. These included: Providing funding for long-term maintenance of program assets; integrating climate change considerations; expanding efforts to deal with predation and invasive species; increased focus on addressing the needs of sturgeon and lamprey; increased attention to toxic contaminants; investigating blocked area mitigation options through a number of activities; and continuing efforts to support ecosystem function through improved floodplain habitats.

When it came time under the Act to call for recommendations to amend the 2014 Program, the Council, in consultation with other program participants, concluded that a wholesale revision of the 2014 Program did not seem necessary. The Council asked the region to focus on two key program needs: 1) how to improve the way the Council and others assess and report on program performance and how to further develop and utilize the program's goals, objectives, and performance indicators to that end; and 2) a small set of near-term needs regarding program implementation. The Council worked, with public input, to focus the 2020 Addendum to the 2014 Program on those two topics.

Based on the recommendations received, the region's experience with implementation following the 2014 Program, and the development work with the region, the 2020 Addendum is structured in two parts. Part I focuses on program performance, reorganizing and supplementing the goals, objectives, and indicators provided in the 2014 Program to enable the Council and others to evaluate program performance in an effective manner. The Council granted requests to extend the scheduled conclusion of Part I for approximately six months to further engage the state and federal fish and wildlife agencies and the region's Indian tribes in a series of workshops on the program's goals, objectives, and performance indicators.

Part II of the 2020 Addendum covered a small set of program implementation needs consistent with the existing and emerging priorities identified in the 2014 Program. These included, among others, re-emphasizing the need to integrate climate change impacts into all areas of implementation; continuing the asset management effort; increasing the scope of mitigation in the blocked areas, especially the work to mitigate for the loss of anadromous fish and the losses to other fish and wildlife species in the areas of Grand Coulee and Chief Joseph dams; implementation of refinements in operations at Libby and Hungry Horse dams; restoring and sustaining the implementation of ocean research studies identified by the Council; sustaining ongoing efforts to reduce predation and increase or revise those efforts as necessary; research to assess benefits of estuarine use by salmon stocks from the interior Columbia River Basin; and more.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-26-18

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

Exhibit 2-71:
Power Council 2029 Power Supply Adequacy Assessment

Pacific Northwest Power Supply Adequacy Assessment for 2029

Northwest Power and Conservation Council

August 2024 | document 2024-4

2029 Adequacy Assessment

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Forward

The Council's annual adequacy assessment is a five-year test of the power plan's resource strategy to ensure that it will provide an adequate future power supply. This report summarizes the Council's assessment of the aggregate regional power supply's adequacy for the 2029 operating year (October 2028 through September 2029).

Analytical results are based on the Council's GENESYS model, which performs a Monte-Carlo chronological hourly simulation of the power system's operation over an entire year. Each study simulates the year's operation many times with different combinations of river flows, temperatures (demand), and wind and solar generation. Projected future river flows, temperatures, and wind generation are derived from climate change data for the Pacific Northwest. The Resource Adequacy Advisory Committee (RAAC), the System Analysis Advisory Committee (SAAC), and other stakeholders played an important role in updating resource and load data, reevaluating operating assumptions, and carefully reviewing the model's power system simulation.

In 2011, the Council adopted a 5 percent annual loss-of-load probability (LOLP) as its measure for adequacy. The power supply was deemed to be adequate when the likelihood of one or more shortfalls occurring during the year is no greater than 5 percent. However, the Council recognizes that today's power system is very different, where significant increases in variable energy resources, such as solar and wind, have added a greater band of uncertainty in system operations. This and other shifts in the power supply, such as increases in distributed generation and changing electricity markets, have made system operations much more complex.

To address this, the Council has enhanced its adequacy model, GENESYS, by significantly improving hourly hydroelectric operations; adding a better representation of unit commitment and balancing reserve allocation; better reflecting electricity market dynamics; and adding other enhancements to more accurately mimic real-life operations. Because of the increasing complexity of the power system and because of the limitations of the LOLP metric, it was imperative the Council also enhance its adequacy standard to capture a more precise measure of customer risk.

To this end, in 2023 the Council transitioned to a more comprehensive multi-metric framework to represent the risk of shortfall frequency, duration, and magnitude, which will be described later in this report. A resource adequacy assessment is only a relative measure of customer risk. It does not draw a bright line between a system with no risk and one with risk. An "adequate" system is not immune to resource shortfalls nor is an "inadequate" system certain to have them. By examining additional adequacy measures, the Council can assess the adequacy of the regional power supply more precisely.

Executive Summary

Over the next five years across the Pacific Northwest, significant load growth and changing system dynamics are creating risks for maintaining power system adequacy. This regional adequacy assessment for 2029 provides early warnings on system adequacy, with specific focus on how the Council's 2021 Power Plan resource strategy supports adequacy given the rapid changes the grid is experiencing, such as announced coal-to-gas conversions and transmission expansion in the region. This adequacy assessment finds that implementing the resource strategy in the plan – specifically achieving energy efficiency consistent with the high end of the Council's target, pursuing renewable deployment of around 6,600 MW by 2029, and ensuring sufficient balancing resources and demand response – will provide for an adequate system. Areas of risk remain, however. The same strategy, but only pursuing the low end of the Council's energy efficiency target, would not provide for an adequate system. Further, if data center load growth accelerates and more closely aligns with utility projections in the region by 2029, the resource strategy will also be insufficient to maintain adequacy. These risk areas, and other changing system dynamics, highlight the importance of the Council's upcoming power plan to provide new guidance to the region in support of an adequate, efficient, economical, and reliable power supply. In the meantime, the Council is continuing to track resource development, load growth trajectories, and other factors to provide timely updates through its Mid-Term Assessment of the 2021 Power Plan.

The Council uses an adequacy model called GENESYS to simulate the region's bulk power system. In each simulation, representing one year, a simulated model shortfall event occurs over a time period when load cannot be served by resources in the model. However, a shortfall in the model does not necessitate an actual blackout will take place. Instead, the modeled shortfall signals that emergency measures are necessary to avoid the blackout. Such emergency measures could include high operating cost resources not in an active utility portfolio, high priced market purchases above normal import limit (such as those that occurred during January 2024's winter storm event), as well as more extreme cases for calls for conservation by government officials (as in September 2022 California heatwave), or curtailment of fish and wildlife hydro operations (as happened during the 2001 Energy Crisis).

While a range of emergency measures are available to operators and decision makers, these measures are not part of the bulk power system modeling in GENESYS. Rather, the Council evaluates shortfalls as a signal for emergency measure needs. Using a new multi-metric adequacy framework, the Council's adequacy approach provides information about the frequency, duration, and magnitude of potential shortfall events, and all metrics must be satisfied with their respective thresholds to yield an adequate system. The metrics include:

1. Loss of load events (LOLEV) sets a limit for the expected frequency of shortfall events to protect against frequent use of emergency measures.
2. Duration Value at Risk sets a limit for shortfall duration to protect against tail-end (extreme) duration use of emergency measures.
3. Peak Value at Risk sets a limit for maximum hour capacity shortfall to protect against tail-end (extreme) magnitude of emergency measures.
4. Energy Value at Risk sets a limit for total annual energy shortfall to protect against tail-end (extreme) annual aggregate use of emergency measures.

The adequacy assessment for 2029 explores how the Council's 2021 Power Plan resource strategy supports an adequate system. The assessment accounts for system changes that will be implemented by 2029, including load growth, in-region resource developments, and out-of-region market fundamentals. Electric load is expected to substantially increase by 2029, due to data centers and electric vehicles. However, announced changes to thermal plant retirements, such as Valmy 1 & 2 and Jim Bridger 1 & 2 conversions from coal to gas fueling, and anticipated transmission expansion throughout the WECC, including Boardman-to-Hemingway in the region, appear to alleviate some of the challenges associated with the increased loads when coupled with the 2021 Plan's resource strategy.

The 2021 Power Plan's resource strategy recommends that between 750 and 1,000 average megawatts of cost-effective energy efficiency, at least 3,500 megawatts of renewable resources, 720 megawatts of low-cost and frequently deployable demand response be acquired, as well as increasing balancing up reserve requirements to 6,000 megawatts to respond to growing short-term uncertainty in variable energy resources (primarily wind and solar) by 2027. Because the resource strategy provides a range for both energy efficiency and renewable development, the Council created a "reference strategy" to test in this assessment. This reference represents the high-end of the Council's cost-effective energy efficiency target (roughly equivalent to 1,300 average megawatts by 2029) and a renewable build consistent with many of the sensitivities analyzed in the plan that informed the strategy (roughly 6,600 megawatts by 2029).

The 2029 adequacy assessment tested a range of potential future conditions, including (1) the reference resource strategy (2) higher data center load growth, and (3) alternative trajectory within the resource strategy – the low end of the energy efficiency target.

The Reference scenario did not violate thresholds in any metric– frequency, duration, and magnitude – and therefore is deemed adequate. The Higher Data Center scenario used all the same assumptions from the reference case, except it added 1,600 average megawatts of additional power demand from the tech sector by 2029. The reference case anticipates roughly 2,400 of incremental tech-related aMW by 2029; the high data center scenario assumes 4,000 aMW. This scenario violated thresholds for all the metrics, and therefore is deemed inadequate. The Alternative Trajectory – Low End EE scenario used the same assumptions as the Reference case, but only met the low end of the efficiency target –

1,000 aMW instead of 1,300 aMW in 2029. This scenario satisfied some metrics (duration and energy), but it violated other metric thresholds (frequency and peak) and therefore is deemed inadequate.

The Reference scenario indicates that the 2021 Plan's resource strategy mostly eliminates summer challenges and greatly mitigates winter challenges – with only a minor set of system conditions that pose adequacy concerns in January evening ramp that are within the acceptable adequacy limits. However, should only the low end of cost-effective energy efficiency target be achieved, the region may experience winter challenges throughout majority hours of the day, with the greatest need in the morning and evening ramps, as well additional challenges in spring and summer. The Higher Data Center scenario further exacerbates the winter, spring and summer challenges as the resource strategy is insufficient to meet the potentially much higher electrification loads.

As the region is facing unprecedented load growth uncertainty driven by data center and transportation electrification, as well as building electrification, the Council will continue tracking and planning for these risk factors in the development of the upcoming Power Plan and the eventual resource strategy to address the evolving needs of the region.

Multi-Metric Adequacy Framework

The Council's multi-metric approach is philosophically different from relying on Loss of Load Probability (LOLP). In the past, adequacy was determined by whether a portfolio/strategy is expected to have no more than 1-in-20 years with at least one shortfall (LOLP of 5%). Instead, the new approach focuses on defining adequacy by whether a portfolio offers the protection against specific shortfall risks that the region wants to avoid.

To define the specific risks – and the metrics and thresholds associated with them - Council staff engaged closely with the Resource Adequacy Advisory Committee (RAAC) and regional partners to evaluate (1) aggregate regional emergency capabilities, and (2) what level of risk is the aggregate emergency capabilities of the region able to protect?

This is a key shift, where the emphasis of adequacy is placed on the significance of interpreting modeled shortfalls from GENESYS – the Council's adequacy model – as a signal for necessary emergency measures to be used to mitigate an actual curtailment.

GENESYS simulates the region's bulk power system. In each simulation, representing one year, a simulated model shortfall event occurs over a time period when load cannot be served by resources in the model. However, a shortfall in the model does not necessitate an actual blackout will take place. Instead, the modeled shortfall signals that emergency measures are necessary to avoid the blackout. Such emergency measures could include high operating cost resources not in an active utility portfolio, high priced market purchases above normal import limit (such as those that occurred during January 2024's winter storm event), as well as more extreme cases for calls for conservation by government officials (as in September 2022 California heatwave), or curtailment of fish and wildlife hydro operations (as happened during the 2001 Energy Crisis). Council staff have distinguished the emergency measures available to the region as Type I and Type II:

1. Type I refers to measures that are typically within a utility's control, such as relying on costly resources outside of the active portfolio, industry back-up generators, load buy-back provisions, and larger and costlier market purchases above market reliance limits.
2. Type II refers to extraordinary measures of extreme cases where customers may experience direct impacts, such as official's call to conservation, emergency load reduction protocols (rolling brownouts), or curtailing fish and wildlife operations.

While a range of emergency measures are available to operators and decision makers, these measures are not part of the bulk power system modeling in GENESYS. Using a new multi-metric adequacy framework, the Council's adequacy approach provides information about the frequency, duration, and magnitude of potential shortfall events – and thus the necessary emergency measures - and all metrics must be satisfied with their respective thresholds to yield an adequate system. The metrics include:

1. Loss of load events (LOLEV) sets a limit for the expected frequency of shortfall events to protect against frequent use of emergency measures.
2. Duration Value at Risk sets a limit for shortfall duration to protect against tail-end (extreme) duration use of emergency measures.
3. Peak Value at Risk sets a limit for maximum hour capacity shortfall to protect against tail-end (extreme) magnitude of emergency measures.
4. Energy Value at Risk sets a limit for total annual energy shortfall to protect against tail-end (extreme) annual aggregate use of emergency measures.

Philosophically speaking, by bridging modeled shortfalls to the need of emergency measures, the Council's multi-metric adequacy framework is aimed at protecting against the risk of Type II emergency measures. As such, quantifying the region's aggregate Type I emergency measures, and setting the metric thresholds to those capabilities, enables a probabilistic approach to how often extreme measures (Type II) are expected. This approach can be summed up as "Let's make sure any emergency measures aren't used too often (satisfying LOLEV)." And, "For the vast majority of the time let's make sure the emergency measures we rely on are not used too long or are too big (satisfying duration, peak and energy VaR)". As will be seen later this section, the significance of the VaR metric at the 97.5th percentile with a threshold associated with type I emergency measures means we can expect to entirely avoid the extreme, less desirable, emergency measures (Type 2) 39 out of 40 years.

However, because it is difficult to fully and accurately account for the magnitude and duration of all emergency measures, staff recognize that thresholds are approximations. Further, there is no clear line in the sand between magnitude of Type I and Type II measures as these may vary by utility and circumstance. As such, the framework should be understood as an evolutionary process towards redefining tail-end system risk than a complete characterization of Type I and Type II measures.

The Council's process to evaluate the metrics and threshold took several years, with 2022 dedicated to developing a provisional framework. The first use of the provisional multi-metric framework culminated in the 2027 Adequacy Assessment, including provisional threshold ranges for each metric to capture both lower and higher risk tolerances. In January of 2023, the Council decided to adopt the new multi-metric framework – and recognizing it will be an ongoing, evolutionary process – tasked staff to collaborate with the region on finetuning the thresholds.

Over the course of 2023, staff engaged with utilities, regional organizations, and public utility commissions to solicit feedback on the multiple metrics, thresholds, and approximation of emergency measures. Interim findings of the stakeholder engagement process were presented at the May 2023 Council meeting and the final findings in January 2024 with the RAAC Steering Committee and Technical Committee.

One important topic that was often raised is the relationship of the Council's adequacy work with the Western Resource Adequacy Program (WRAP) managed by the Western Power Pool. The roles of the Council and WRAP are complementary: the Council develops a long term, 20-year power plan, with recommendations for a six-year resource strategy for the region to ensure adequacy, while the WRAP focuses on near-team planning to ensure resource adequacy. As often discussed in the RAAC, the success or failure of the WRAP is a concern on stakeholders' minds for maintaining regional adequacy, and staff continue to engage closely with the WPP for long-term collaboration.

The outcome of the process is summarized in Figure 1, which maps the change from provisional thresholds to an interim recommendation that was used in this 2029 adequacy assessment. Modifications included (1) aligning LOLEV with the WRAP's seasonal use of Loss of Load Expectation (LOLE), but still report annual LOLEV, and (2) alongside Peak VaR and Energy VaR also report the Normalized VaR (NVaR) – as non-binding metrics - to provide comparative perspectives with utilities that report some normalized metrics.

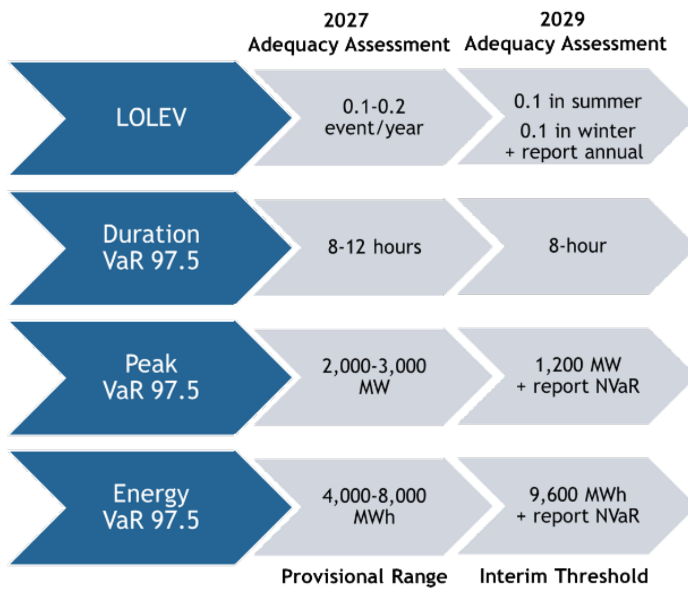


Figure 1. Evolution of metric thresholds

The following sections describe the metrics with greater details. For full descriptions and metric summaries, please see past RAAC presentations.

Loss of Load Events (LOLEV) to protect against frequent use of emergency measures

As the frequency of shortfalls is equivalent to the frequency of using emergency measures, a limit can be set for the frequency of simulated shortfalls as it relates to preventing overly frequent use of emergency measures.

The metric chosen to achieve this objective is the Loss of Load Events (LOLEV), which is the expected number of shortfall events per year. A shortfall event is a set of contiguous hours of unserved demand. LOLEV is equal to the total number of shortfall events divided by the total number of simulation years.

Because periods of most concern include summer and winter staff heard feedback to align with the WRAP seasonal approach, and decided set a threshold value for both summer and winter at 0.1. However, system risk may change over time, so considering shortfall risk in spring and fall is deemed important as well. Therefore, the Council's adequacy studies also report an annual LOLEV (threshold of 0.1) to cover risk throughout the course a year.

Duration VaR to protect against tail-end (extreme) duration use of emergency measures

Long shortfall events can indicate insufficient system energy (fuel). However, as described earlier, a simulated shortfall event is not the same as a curtailment event, although it could turn into one if emergency measures are not enough to offset the peak and energy shortfalls of the event. Therefore, setting a limit for shortfall event duration is a critical part of maintaining an adequate supply.

Furthermore, long shortfall events can indicate insufficient system resiliency, where resiliency is defined as the ability of a power system to protect against – and quickly recover from – high impact, low-frequency events. Such events can occur in extreme weather (heat waves or cold snaps); significant loss of transmission (wildfires, ice storms, heavy winds) or loss of a major fuel supply (gas pipeline rupture). The metric chosen to achieve this objective is the Value at Risk (VaR) for shortfall event duration at the 97.5th percentile over all simulation years.

To calculate this metric, the duration of the longest shortfall event for each simulation year is recorded (and noted as zero if there is no shortfall). The Duration VaR97.5 is the 97.5th percentile of the distribution of this record from all simulation years. Choosing the 97.5th percentile limits the risk of an excessively long shortfall event to no more than once per 40 years. While this frequency is much smaller than that chosen for the LOLEV (no more than once per 10 years), it represents the risk of a real curtailment and not just a shortfall. The limit for this metric is set to 8 hours, to reflect the minimum shortfall duration that could lead to severe customer risk. Conditions that might trigger a long duration shortfall include extreme weather events, wildfires, and high winds – any event that disrupts major transmission lines or fuel supplies.

Peak VaR to protect against tail-end (extreme) magnitude of emergency measures

The Pacific Northwest's power supply has historically been capacity long but energy short. The region has had an excess of peaking capacity (machine capability) but continues to be limited by the water supply that powers the hydroelectric system, which provides more than half of the grid's nameplate capacity.

While the hydroelectric system's nameplate capacity is about 35,000 megawatts, it generates about 16,000 average megawatts per year, on average, and only about 12,000 average megawatts during a low water year. However, due to significant increases in variable energy resources, changes in hydroelectric operating constraints, and other added complexities, the region can no longer assume that it has sufficient capacity to meet all demand. Thus, it is important to include a metric to protect against excessively high-capacity shortfalls.

The metric chosen to achieve this objective is the Value at Risk (VaR) for capacity shortfall at the 97.5th percentile over all simulation years. To calculate this metric, the highest single-hour shortfall for each simulation year is recorded (or noted as zero if there is no shortfall). The Peak VaR97.5 is the 97.5th percentile of the distribution of this record from all simulation years. Choosing the 97.5th percentile limits the risk of an extreme high-capacity shortfall to no more than once per 40 years. While this frequency is much smaller than that chosen for the LOLEV (once or twice per 10 years), it represents the risk of exceeding type I emergency measure capability (implying that the more extreme, type II measures, could be needed), whereas the LOLEV frequency represents the risk of using emergency measures too often. The limit for this metric represents the amount of single hour demand the region is willing to risk. As such, the limit could be set equal to the aggregate amount of reliable emergency peaking capability. The risk of real curtailment is high when the Peak VaR97.5 exceeds this limit because avoiding a loss of service depends on the availability of extraordinary emergency measures not accounted for in the adequacy limit. The interim limit for this metric is set at 1,200 megawatts. The non-binding reported Peak NVaR 97.5 threshold is 3% (1,200 MW is approximately 3% of average peak load the region).

Energy VaR to protect against tail-end (extreme) annual aggregate use of emergency measures

The region's power supply continues to be energy limited because hydroelectric resources make up the lion's share of the supply. It is important to include a metric to protect against extreme annual energy shortfalls. But unlike the capacity metric, whose limit is tied to the highest single-hour shortfall, the energy metric must be tied to the entire year's unserved energy. This is because energy shortfalls are often equated to a lack of fuel, whereas capacity shortfalls are often equated to a lack of machine capability. Once the machine capability is sufficient to offset the highest capacity shortfall, all other capacity shortfalls can also be offset. However, simply having sufficient fuel to offset the highest energy shortfall does not guarantee that other energy shortfalls throughout the year can also be offset.

The metric chosen to achieve this objective is the VaR for energy shortfall at the 97.5th percentile over all simulation years. To calculate this metric, total annual unserved demand for each simulation year is recorded (or zero if there is no shortfall). The Energy VaR97.5 is the 97.5th percentile of the distribution of this record from all simulation years. Choosing the 97.5th percentile limits the risk of an excessively high annual energy shortfall to no more than once per 40 years. Similar to Peak VaR, this frequency is much smaller than that chosen for the LOLEV, representing the risk of exceeding type I emergency measure capability.

The limit for this metric represents the amount of annual energy demand the region is willing to risk. As such, the limit could be set equal to the aggregate amount of reliable emergency energy generating capability. The risk of real curtailment is higher when the Energy VaR97.5 exceeds this limit because avoiding a loss of service would depend on the availability of emergency measures not accounted for in setting the adequacy limit.

Because it is difficult to accurately assess the amount of available emergency energy, alternative approaches can be used to set the VaR97.5 limit. By considering the "worst acceptable" annual unserved energy as the longest allowed 97.5th duration of 8 hours, where each hour has the largest allowed 97.5th hourly peak magnitude of 1,200 MW, the limit can be set at 9,600 MWh for the year. The non-binding reported Energy NVaR 97.5 threshold is 0.0052% (9,600 MWh is approximately 0.0052% of average annual energy in the region).

Updates to load growth in 2029 since 2027 Assessment

The region is anticipating rapid load growth, driven by forecasted data center growth and transportation electrification. However, there is uncertainty regarding how much load will materialize from both sectors. This load uncertainty poses a risk for adequacy, as the region may need to respond to a rapid increase in load as data centers and electric vehicles arrive. To help account for load uncertainty, two data center load growth trajectories are tested. The load forecast for the 2029 resource adequacy assessment is projecting higher loads than the 2021 Power Plan Long Term Forecast for 2029. The higher 2029 forecast is attributable to:

1. Forecast Timing – the Resource Adequacy Assessment Forecast for 2029 has three additional years of recent load, weather and economic history to work with
2. Much of the growth in load projections is explained by updated information about forecasts for data centers, chip fabrications, and electric vehicles

3. Additional growth projected beyond these two drivers – such as changes to population growth following historical trends, or some facets of efficiency that is being missed

Data centers and chip fabrication loads

Data center and chip fabrication loads (tech loads) are projected to be a driver of load growth in the Northwest. There is substantial uncertainty regarding how much load they will bring to the region. Figure 2, below, provides a range of incremental tech load forecasts in gray. By 2029, the range spans from a floor of 1,800 aMW of new load, to a ceiling of 6,500 aMW. All of these loads are assumed to be flat across the year.

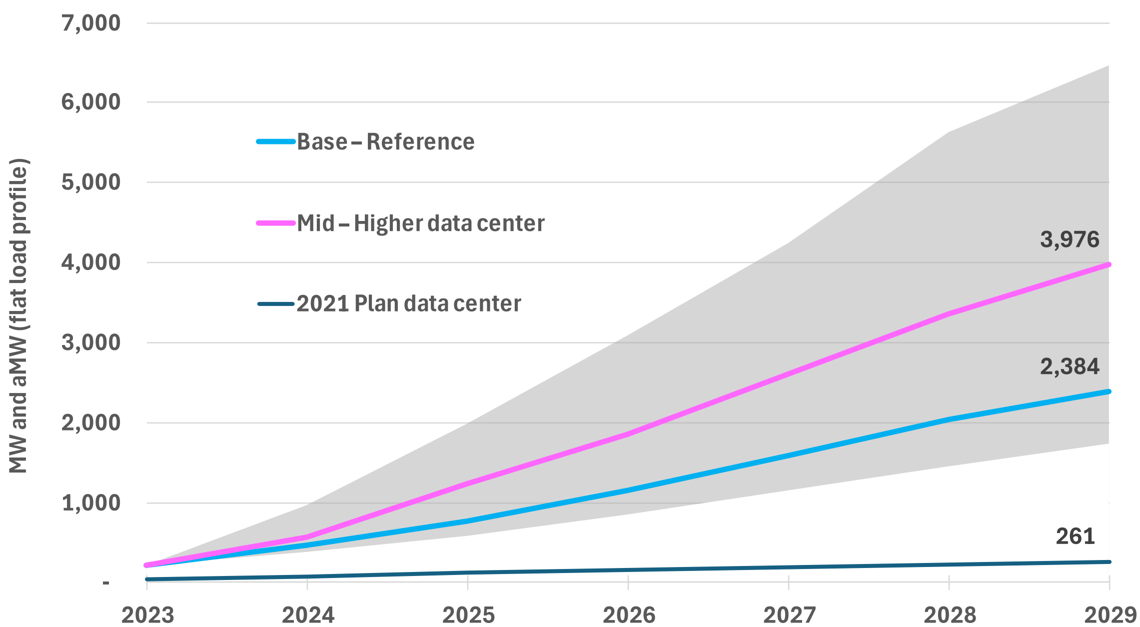


Figure 2. Incremental data center and fab growth forecast, 2023 to 2029

For this adequacy assessment two tech load forecasts are used to capture the load uncertainty. The base forecast, shown in light blue, assumes recent development trends will continue and incorporates recently announced projects. It adds around 2,400 aMW of new load to the Northwest by 2029. The mid case, in pink, assumes an acceleration in tech project development and is closer to what the region's utilities are projecting. It adds nearly 4,000 aMW of new load to the region by 2029. The description of the full scenarios tested is provided in the "Scenario Description" section (page 23).

Electric vehicles

Unlike data center load in the 2021 Power Plan, transportation electrification load was already gaining traction with earlier forecasts showing increased demand from electric vehicles (EV) in the region. In efforts to enhance the EV forecast for the 2029 adequacy assessment, Council staff evaluated several EV forecasting models and datasets to forecast (1) annual vehicle fleet and demand by state and balancing authority (BA) of light duty vehicles (LDV), medium duty vehicles (MDV), and buses, and (2) hourly charging profiles. To derive BA level data, BA allocation factors were calculated using estimates of vehicle registration locations, and when available, compared against utility IRP forecasts. The models and datasets included PNNL's GODEEP dataset for EV forecast by BA, Energy Policy Simulator (EPS, state level) by Energy Innovations and Rocky Mountain Institute, and California Energy Commission (CEC) charging forecasts. Forecasts were compared to actuals (2020-early 2024) and the 2021 Power Plan High Electrification scenario – which included high penetration of EVs – for comparison.

Table 1 provides the summary of transportation electrification data assumptions. Because actuals for Washington and Oregon (especially LDV, the bulk of the fleet) resembled EPS and 2021 Power Plan High Electrification, staff determined that using the existing High Electrification forecasts for LDV was appropriate. However, for MDV and buses, EPS results were utilized but scaled to 2021 Power Plan using LDV factors. Charging profiles for LDV, MDV and buses all assumed to be influenced by time-of-use (TOU) rates, derived from CEC profiles. TOU rates can have substantial impact on charging behavior, mainly lowering the peak demand in late afternoons and evenings by spreading the charge over periods of less demand and costly electricity either during the night or midday. Staff assumes that by 2029 utilities will adopt TOU for EVs as a cost-effective response to handling EV load growth, and will continue monitoring policies and EV sales across the four states as on-going work towards future forecasts.

Table 1. Summary of transportation electrification data assumptions

Vehicle Type	Fleet Method	Demand Method	Charging Profile
Light Duty Vehicle (BEV and PHEV)	2021 Power Plan High Electric Forecast	Demand by state for light duty passenger cars and trucks - from the 2021 Power Plan High Electric Forecast	California Energy Commission time-of-use LDV profiles
Medium Duty Vehicle (BEV Light & Medium Freight)	EPS forecast results for fleet were used as a base and scaled to the power plan forecast using the LDV factors.	Demand by state calculated using average use rates (MWh/Vehicle year) from PNNL and EPS and applied to the fleet to estimate demand	Charging profile from California Energy Commission time-of-use MHDV profiles
Bus (BEV Public transit and school)	EPS forecast results for fleet were used as a base and scaled to the power plan forecast using the LDV factors	Demand by state calculated using average use rates (MWh/Vehicle year) from PNNL and EPS and applied to the fleet to estimate demand	Charging profile from California Energy Commission time-of-use bus profiles

The result of the hybrid approach to the regional EV forecast, provided in Figure 3, show that that expected EV load by 2029 is 1,147 average megawatts (and ~5,000 aMW in 2045, not shown in graph). Light duty vehicles account for 87% of the share, with MDV and buses starting to pick up after 2025. The majority of forecasted EV load is in Washington (65%) and Oregon (30%). In terms of electric fleet size, the region is expected to have over 1.82 million LDVs, over 51,000 MDVs, and over 7,000 buses by 2029.

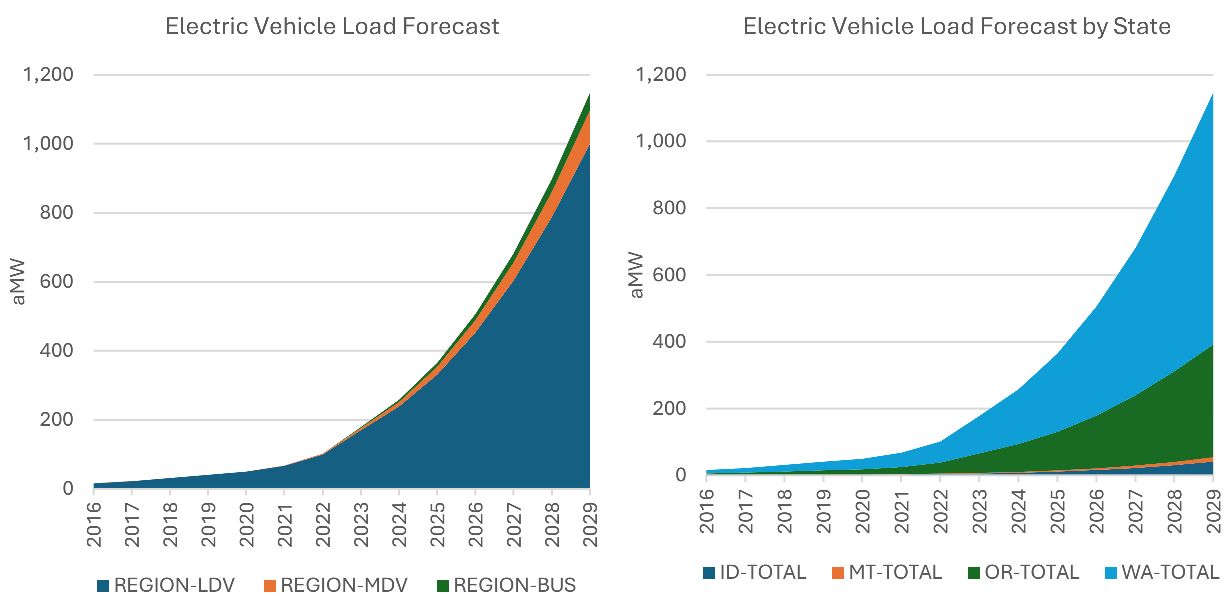


Figure 3. Electric vehicle load forecast by region and state

Other system changes since 2027 Assessment

Alongside expected yet uncertain load growth, there are additional changes to the regional power system that are important to consider since the 2027 assessment, including (1) announced thermal retirement changes of coal-to-gas conversion, (2) expanded transmission capacity, and (3) hydro changes from the Resilient Columbia Basin Agreement (RCBA, Appendix B) to the Lower Snake and Lower Columbia projects.

Thermal coal-to-gas conversions

The interaction of decarbonization policies, adequacy concerns with extreme weather events, and the economics of thermal plants paved the way for changes to announced decommissioning of several coal plants in the region. But instead of maintaining operations as usual, coal plants can be converted to gas, a process known as "coal-to-gas conversions."

Major coal plants in the region that were originally planned for decommissioning have now shifted to coal-to-gas, seen in Table 2 and Figure 4. This amounts to a substantial resource addition since the 2027 adequacy assessment totaling. These plants include Jim Bridger 1 and 2 (~1,200 MW) and North Valmy 1 and 2 (~280 MW) for a total of ~1,480 MW of thermal plants, which could have direct adequacy benefits to the region that is expecting substantial load increase of 3,400-5,000 aMW.

Table 2. Announced coal decommissioning and coal-to-gas conversions

Coal Unit	Nameplate Capacity (MW)	Planned Retirement (Feb 2024)	Planned Retirement (2021 Plan)
Colstrip 1	358	2020	2020
Colstrip 2	358	2020	2020
Boardman	601	2020	2020
Centralia 1	730	2020	2020
Jim Bridger 1	608	2024*	2023
Jim Bridger 2	617	2024*	2028
Centralia 2	730	2025	2025
North Valmy 1	277	2025[x]	2021
North Valmy 2	289	2025[x]	2025
Colstrip 3	778	–	–
Colstrip 4	778	–	–
Jim Bridger 3	608	2030*	–
Jim Bridger 4	608	2030*	–

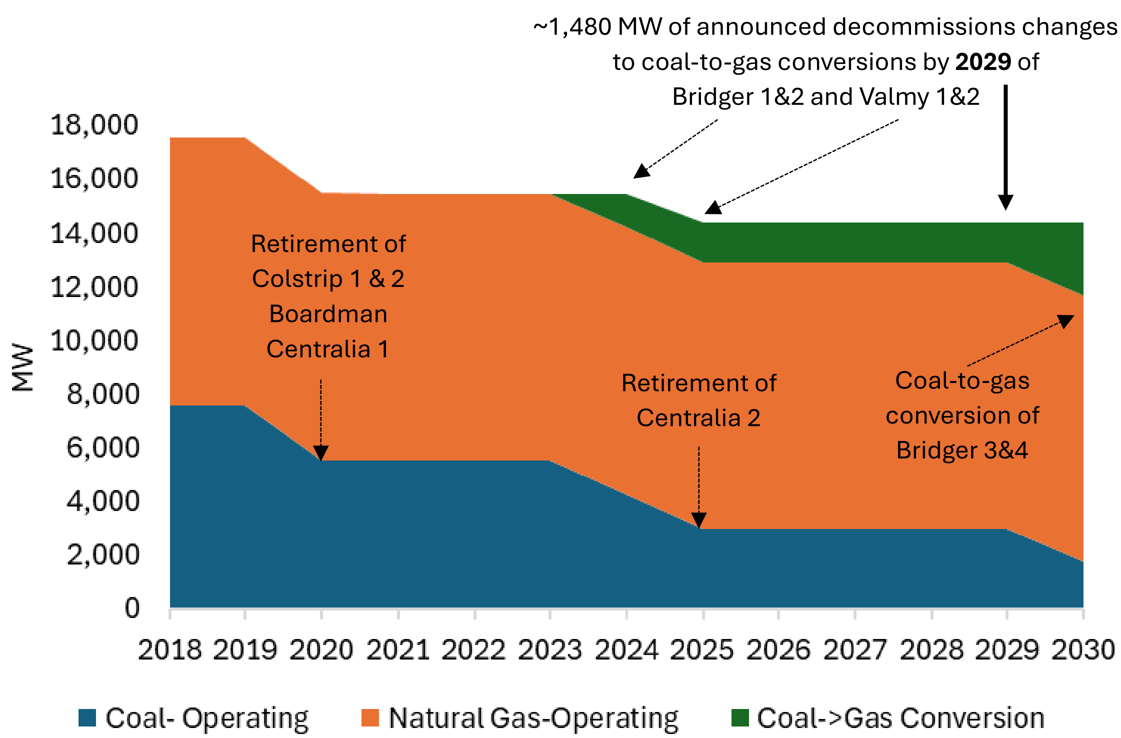


Figure 4. Cumulative thermal capacity changes in the region

Expanded transmission capability

Several major transmission expansion projects are slated to begin throughout the WECC in the coming years, including Boardman-to-Hemingway (B2H) in the PNW region. For the 2029 assessment, staff included projects that have already been announced as close to completion, started construction, or with high likelihood of being completed by 2029. Table 3 and Figure 5 below detail the new transmission expansion lines and their modeling topology. In total, 12,700 MW of transmission capacity will be added throughout the WECC, with B2H providing 1,000 of additional east-west capacity in the region between Idaho Power and BPA.

Table 3. Transmission expansions in 2029 Assessment

Planned Transmission	New Capacity (MW)	Path	Online Date	GENESYS Buses	Existing Today (MW)	New 2029 capacity (MW)
● Ten West Link	3,200	SCE to APS	2024	So_Cal to Arizona	1,400	4,600
● SunZia	3,000	PNM to APS	2026	New Mexico to Arizona	1,700	4,700
● Transwest Express	3,000	WAPA Wyoming to PACE UT	2027	wapa RM to PAC_UT	650	3,650
● Transwest Express	1,500	PACE UT to Nev South	2027	PAC_Ut to Nevada South	250	1,750
● SWIP North	1,000	IP to North Nevada	2027	IP to north Nevada	350 | 185	1,350|1,185
● B2H	1,000	IP to BPA_OR	2026	IP to BPA_OR	2,000	3,000

The expanded transmission capability in the region could have adequacy benefits by alleviating transmission congestion across the Cascades and enabling greater flow across the region. This is especially beneficial as more wind resources are built in Montana and Wyoming to serve load west of the Cascades.

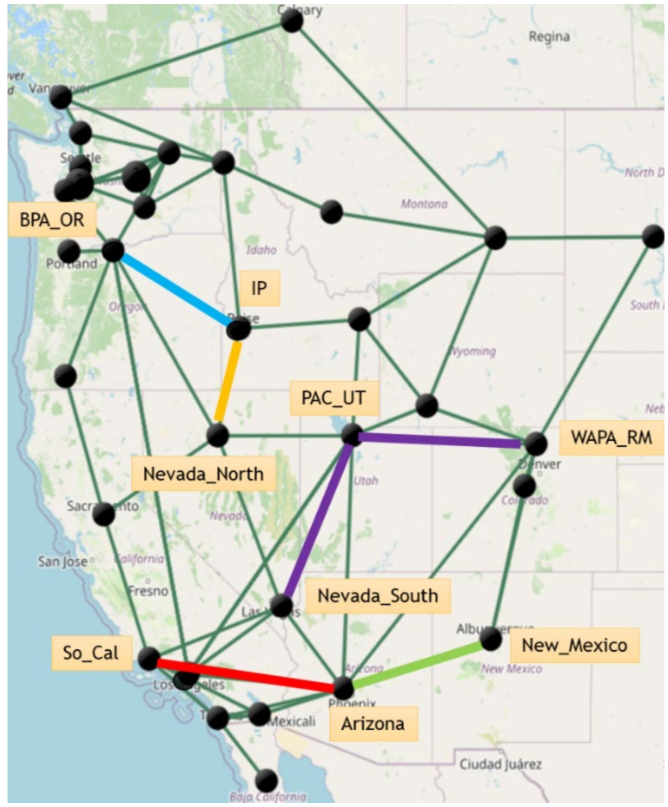


Figure 5. Transmission expansions in 2029 Assessment

However, the other transmission projects, while beneficial for the region, do not necessarily have the same adequacy benefit to the region as B2H. This is the case because of the market reliance limit for adequacy used by the Council. Though the new capacity would help WECC-wide market dynamics, including the export and import capability of SWIP North through Idaho Power, the overall import limit (set for adequacy) is well below the existing (current, pre-capacity expansion) capability of the transmission lines between the region and WECC.

In other words, the Council's winter market reliance of 2,500 MW and a summer reliance limit of 1,250 MW are the limiting factor for import capability from outside of the region. This limit was set to hedge against the risk of relying on the market at times of need and differs seasonally due to the fact the PNW peaks in winter and the WECC in summer. The market reliance limit, and market fundamentals in general, are routinely discussed in the Resource Adequacy Advisory Committee and the System Analysis Advisory Committee, and in the meantime the limit is the preferred path. Future considerations could change the decision, which will be discussed in future advisory committees and Council meetings.

RCBA Appendix B: Changes to Lower Snake and Lower Columbia

For power planning and resource adequacy assessments, the Council's Power Division staff aims to model the existing system to the best of their capabilities. An important piece of this work is to model the hydro operations consistent with any requirements for river operations. To that end, staff recently made updates to the Council's GENESYS model to reflect changes to hydro operations resulting from the Resilient Columbia Basin Agreement (RCBA, Appendix B) to the Lower Snake and Lower Columbia projects. Issued in December 2023, the changes are geared to increase spill for improved juvenile fish survival in the Lower Snake and Lower Columbia.

The impact of increased spill is reduced spring and early summer hydro generation. There is minor hydro generation reduction in the fall and winter, varying by project. However, an increase in hydro generation is expected in August. In addition to monthly changes in average hydro generation, minor changes in daily hydro generation flexibility are also expected.

From an adequacy perspective, while hydropower is slightly reduced, based on the limited subset of studies used for a comparative study, the changes do not lead to a significantly different regional adequacy result. Offsetting the reduced hydropower is a small increase in regional thermal generation and market reliance, yet within the market reliance limit, throughout most of the year, especially at night.

Since completion of the analysis for the 2029 adequacy assessment, an Agreement in Principle on the changes of the Columbia River Treaty has been made by the US and Canadian governments. The Council will continue to evaluate the impact on power system planning and resource adequacy in future analyses.

Scenario description

As an adequacy assessment, the main goal is to test the resource strategy outlined in the Power Plan given potential risk scenarios to signal to the region about adequacy and areas of concern. As a reminder, the resource strategy, provided in Figure 6, of the 2021 Power Plan to achieve by 2027[1] includes (1) at least 3,500 MW of renewable resources, (2) 750-1,000 aMW of energy efficiency, (3) 720 MW of demand response, and (4) doubling the balancing up reserves to hold 6,000 MW to support integration of renewables.

2029 Resource Strategy – the reference

In this assessment, looking 2 years past 2027, the resource strategy in 2029 continues the trajectory of resource assumptions used in 2027 reference case, seen here:

Figure 6. 2021 Power Plan resource strategy

Table 4. Comparison of 2029 and 2027 reference strategy

Portfolio	2029 Adequacy Assessment	2027 Adequacy Assessment
Renewables	6,600 MW	5,900 MW
EE	1,300 aMW	1,000 aMW
DR	720 MW	720 MW
Reserves	6,000 MW	6,000 MW

[1] See pages 46-48 in the 2021 Power Plan Section 6: Resource Development Plan as well as page 107 in the 2021 Power Plan Section 9: Cost Effective Methodology for Providing Reserves

The 700 MW increase in renewables is consistent with several buildouts observed in the 2021 Power Plan and the higher range of renewables tested in 2027, seen in Figure 7. The additional 300 aMW of energy efficiency is consistent with the assumption of reaching the high end of the cost-effective energy efficiency target.

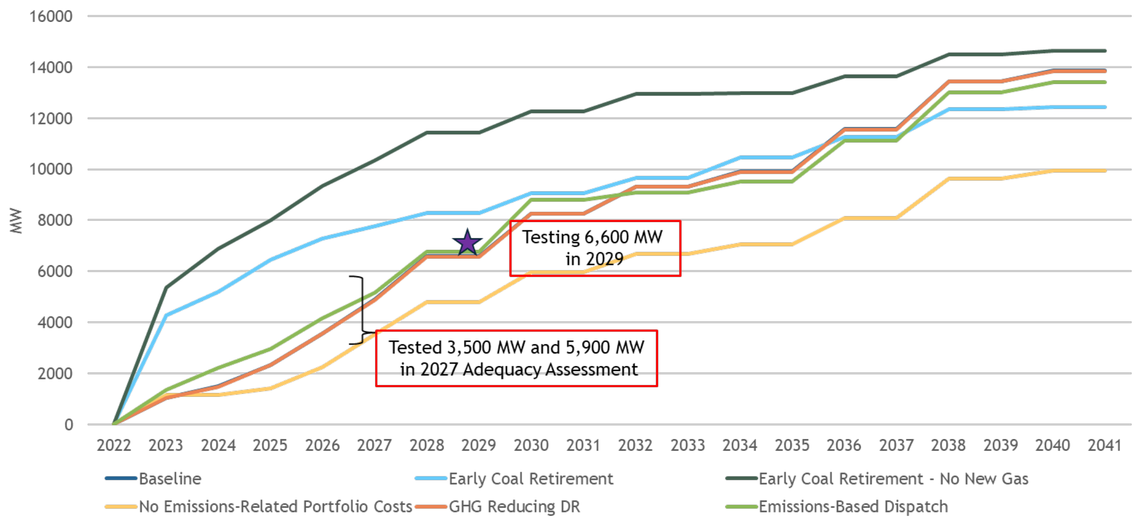


Figure 7. Example of renewable buildout trajectories from the 2021 Power Plan Resource Strategy

The scenarios

Staff engaged with the RAAC and SAAC to define the risks and setup to test for the assessment, resulting in the following list of potential scenarios:

1. Reference
2. Higher data center load (in region)
3. Alternative Trajectories within Resource Strategies (low end of energy efficiency target)
4. In-region gas supply limitations
5. Earlier availability of transmission (reconductoring in region)
6. Delayed availability of transmission and emerging tech in WECC
7. Emission pricing

While all scenarios provide important adequacy insights to the region, given budget constraints and proximity to preparation for the next Power Plan, staff had to prioritize three key scenarios for the assessment (in green), including a reference case, a higher data center load case, and an alternative to the resource strategy case that only achieves the low end of the cost-effective energy efficiency target. The other scenarios (in red) include financial risks that would be considered in upcoming wholesale market forecast, and broader system risks (adequacy and resource strategy) in the next Power Plan. Thus, the tested scenarios differ in terms of energy efficiency savings and Data Center Loads, but share the same EV loads. Seen in Table 5, the Higher Data Center scenario tests the same resource strategy as the Reference against ~1,600 aMW of additional load. The Low End EE scenario tests the same data center load as the Reference, but with 300 aMW less of EE.

Table 5. Load difference across 2029 adequacy assessment scenarios

Scenarios	EE Savings (aMW)	EV Loads (aMW)	Data Center Loads (aMW)
2029 Reference	1,300	1,048*	2,386
2029 Low End EE	1,000	1,048*	2,386
2029 Higher Data Center	1,300	1,048*	3,976

* Value for 2029 incorporates the 1,147 aMW (Section 4) but subtracts the embedded EV load in the base forecast in 2022. Hence, there is an additional 1,048 aMW to reach the 1,148 aMW by 2029.

The expected annual load, and average peak load by season for each of the scenarios is provided in Table 6 from simulation results.

Table 6. Average simulated loads from 2029 adequacy assessment scenarios

Scenario	Average Annual Load (aMW)	Oct-Mar Avg Peak (MW)	Apr-Sep Avg Peak (MW)
Reference	25,271	36,724	34,034
Low End EE	25,495	36,947	34,291
Higher Data Center	26,861	38,314	35,624

The Council uses three separate climate change scenarios, with each possessing 10 unique sets of climate-dependent hydro-load combinations, and six wind generation profiles that total in 180 simulations per study (10 hydro-load combinations x six wind profiles x three climate scenarios). Generally, each of the climate scenarios represents a risky hydro-load profile: CanESM (scenario A) captures more risk of low summer hydro generation and higher summer loads, CCSM (scenario C) captures high winter hydro with early runoff lower summer hydro conditions. Lastly CNRM (G) captures risk of low winter generation with higher winter loads.

These simulated loads highlight the potential system risks that the resource strategy needs to address throughout the year. In fact, certain load conditions in scenario G surpass 41,000 MW at peak system needs even at the Reference scenario. The results section will explore the type and timing of shortfalls and lead way to understand the adequacy risk for the region.

2029 Assessment results

Despite the substantial load growth, this assessment finds that implementing the resource strategy in the 2021 Plan – achieving energy efficiency consistent with the high end of the Council's target, pursuing renewable deployment of around 6,600 MW by 2029, and ensuring sufficient balancing resources and demand response – will provide for an adequate system in 2029 as all adequacy metrics for the Reference scenario have been satisfied. Given the additional system changes, the region likely maintains adequacy due to the mitigating benefits of coal-to-gas conversions of Jim Bridger 1 & 2 and Valmy 1 & 2, as well as the added B2H transmission expansion (alleviating congestions and enabling greater east-west transfer in the region).

However, the region still faces adequacy risks, even with the additional system changes. Pursuing the same resources strategy as the Reference but only achieving the low end of the cost-effective energy efficiency target (1,000 aMW instead of 1,300 aMW in 2029) would not result in an adequate system. Seen under the Low End EE results, the scenario satisfied the duration and energy metrics, but violated the frequency (winter) and peak metrics and therefore is deemed inadequate.

Furthermore, should data center load growth accelerate and exceed current trends to match high-end trajectories of utility projections by 2029, the resource strategy will also be insufficient to maintain adequacy as the Higher Data Center scenario violated all adequacy metrics. A qualitative high level summary of the 2029 adequacy assessment is provided in Figure 8.

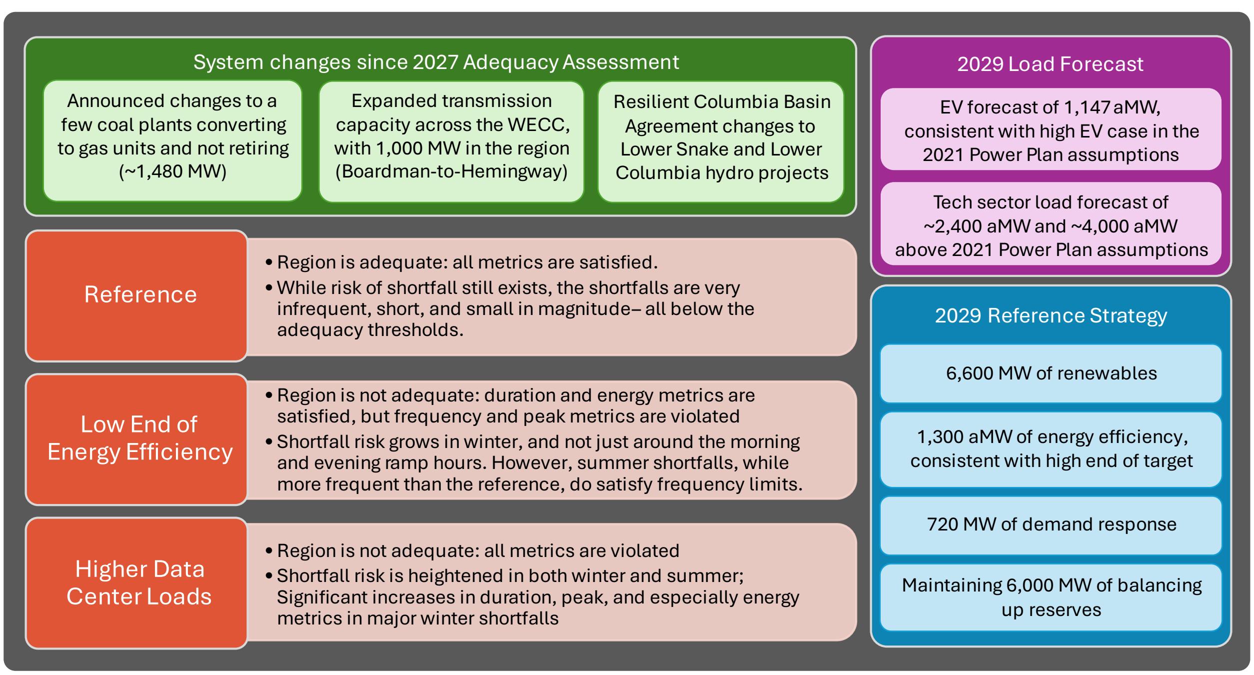


Figure 8. High-level summary of 2029 Adequacy Assessment

The results of the adequacy metrics across the scenarios are provided in Table 7. While a value of "0" might appear odd for the Duration and Peak and Energy VaRs, it does not mean there is no shortfall risk. Rather, it is a probabilistic representation signaling the shortfall risk in 39 out of 40 years is extremely low. As will be described in more detail later, the shortfall risk under the Reference scenario only start at the 98.8th percentile, and become substantial after the 99.5th percentile. In fact, out of 180 simulation years in the Reference scenario, only 4 experienced at least one shortfall (1-event year), with 9 shortfall events in total. Considering the summer and winter LOLEVs of 0.022 and 0.017, the implication is that the resource strategy, alongside with the changes to thermal coal-to-gas conversions and B2H, the region would expect one shortfall in the summer every 45 years, and one shortfall in winter every 58 years. Relating this to LOLP – solely for comparative perspectives as LOLP is not used - the Refence scenario results with an LOLP of 2.2%, well below the previous LOLP metric threshold of 5%.

Table 7. Adequacy metric results

Type	Metric	Threshold	Reference	Low End EE	Higher Data Center
Frequency	Winter LOLEV	0.1	0.022	0.350	1.294
Frequency	Summer LOELV	0.1	0.017	0.033	0.3
Duration	Duration VaR 97.5	8 hours	0	1.5	20.6
Magnitude	Peak VaR 97.5	1,200 MW	0	1,567	3,076
Magnitude	Energy VaR 97.5	9,600 MW	0	4,196	196,324

The risk is different with only achieving the low end of the energy efficiency target. From a frequency perspective, the number of winter events (winter LOLEV) exceeds the threshold (1-event in 2.85 years instead of not more than 1-event in 10 years), but summer is satisfied (1-event in 30 years). This highlights the benefits of achieving the high end of energy efficiency in protecting against winter events. Duration wise, the Low End EE does protect against long duration shortfalls, indicating that 39-out-of-40 years shortfalls will be at or below 1.5 hours long. Lastly, while Energy VaR is satisfied, with 39-out-of-40 years expecting the annual aggregate shortfall to be half of the energy threshold, Peak VaR is violated – by 367 MW. This situation is helpful in illustrating the importance of considering both the peak hourly shortfall and aggregate annual shortfall; in terms of emergency measures – there is enough emergency "fuel" in the system on an annual basis, but enough hours lack the emergency capacity to mitigate larger shortfalls. From the 180 simulation years, the Low End EE scenario had 14-event years (LOLP of 7.8%) with 80 shortfall events in total.

Under the Higher Data Center scenario - which the resource strategy and system changes do not mitigate the risk of increased loads - the metrics are violated to even a greater degree. Both winter and summer are well above the threshold, with winter especially vulnerable to frequent events, and the risk of long duration shortfalls surpass the limit by 2.65 times (21 hours at the 97.5 percentile). In terms of Peak VaR, the metric exceeds the threshold by 1,876 MW (at 3,076 MW), but the Energy VaR sheds light on the tail-end risk of aggregate annual fuel availability – the metric is 20 times the threshold at 196,324 MWh. This difference further highlights the need of different considerations of solutions for higher load futures. From the 180 simulation years, the Higher Data Center scenario had 24-event years (LOLP of 13.3%) with 296 shortfall events.

Aside from the above metrics used to determine adequacy, the three non-binding reported metric (Annual LOLEV, Peak NVaR and Energy NVaR) provide additional perspectives for comparative risk, seen in Table 8. The results echo the same outcome with the adequacy metrics – the Reference satisfies all non-binding metrics, the Low End violated annual frequency and Peak NVaR but satisfied Energy NVaR, and the Higher Data Center violated all metrics.

Table 8. Results of reported (non-binding) metrics

Type	Non-Binding Reported Metric	Threshold	Reference	Low End EE	Higher Data Center
Frequency	Annual LOLEV	0.1	0.05	0.444	1.644
Magnitude	Peak NVaR 97.5	~3%	0	4.2%	9%
Magnitude	Energy NVaR 97.5	~0.0052%	0	0.002%	0.09%

Shortfall statistics

As seen with the metrics, while both the Low End EE and Higher Data Center scenarios are inadequate, the risk they pose is not the same. Comparing some of the metric results helps explain this. To understand the adequacy risk of the three scenarios to the region, a closer examination of the shortfall statistics – and distributional characteristics – is warranted.

Frequency

From a frequency perspective, considering that the annual LOLEV is higher than the sum of summer and winter LOLEVs suggested that there are events also occurring in spring and fall. As such, staff explored the seasonal LOLEVs, presented in Table 9. One interesting find is the indication of events in the spring, including in the Reference case. While very low expected spring-event frequency (one in 91 years) in the Reference case, the Low End EE spring-event frequency is higher than the summer. Though spring events are still infrequent

(1-in-22 years), as is fall event frequency (1-in-59 years) it raises the awareness of monitoring shoulder seasons. This is especially important given maintenance timing that could coincide with challenging system conditions that could stress the system towards a shortfall.

Table 9. LOLEV across the seasons

LOLEV Period	Months	Threshold	Reference	Low End EE	Higher Data Center
Winter	Dec-Feb	0.1	0.022	0.350	1.294
Summer	Jun-Aug	0.1	0.017	0.033	0.300
Annual	All	0.1	0.050	0.444	1.644
Spring	Mar-May	0.1?	0.011	0.044	0.039
Fall	Sep-Nov	0.1?	0.000	0.017	0.011

VaR duration, peak and energy

The next several charts capture (1) the distribution of shortfall statistics (i.e. max duration shortfall, max peak shortfall, and annual energy shortfall from each of the 180 simulations per scenario), and (2) the actual distribution counting all events in each scenario. For the distribution of shortfall statistics, the total amount of observations (per metric) is 180. However, most of the simulation years had no shortfalls and therefore 0 will be recorded. For example, recall that the Reference scenario only had 4 event-years, so the shortfall statistic only records 4 non-zero duration, peak and energy values, and 176 zeros. Likewise, the Low End EE only records 14 non-zero values, and 166 zeros. Lastly, the Higher Data Center scenario has 24 non-zero values and 156 zeros.

Ranking the non-zero observations of each metric is an easy way to understand the percentile approach. The largest observation in each metric represents the 100th percentile, and the lowest non-zero observation is the percentile where shortfalls start occurring. Only non-zero observations are included in the graphs. Repeated non-zero values in the same study are also removed. It's also good to remember when examining the metric distributions that observations to the left of the VaR 97.5 vertical lines may be much larger than the threshold. By definition, the framework does not intend to protect against them. What matters is that the 97.5th percentile is at or below the threshold to satisfy a tail-end risk in 39-in-40 years.

A good example of this is featured in the max duration curves of the studies in Figure 9, especially the Low End EE scenario. The Duration VaR 97.5 value is 1.5 hours, satisfying the 8-hour threshold. However, the maximum shortfall durations in the study are 22, 21, 18, and 11 hours, followed by 2 and 1 hours. The risk of 22, 21 and 18-hour long duration shortfalls is substantially smaller than 1-in-40 years. However, in the Higher Data Center scenario, the Duration VaR 97.5 value is 21 hours, a continued risk up to the 96th percentile, with much longer extreme shortfall durations (up to 120 hours). Under the Reference scenario, all duration metric values were below the threshold, including the maximum (100th percentile) of the study at 4 hours.

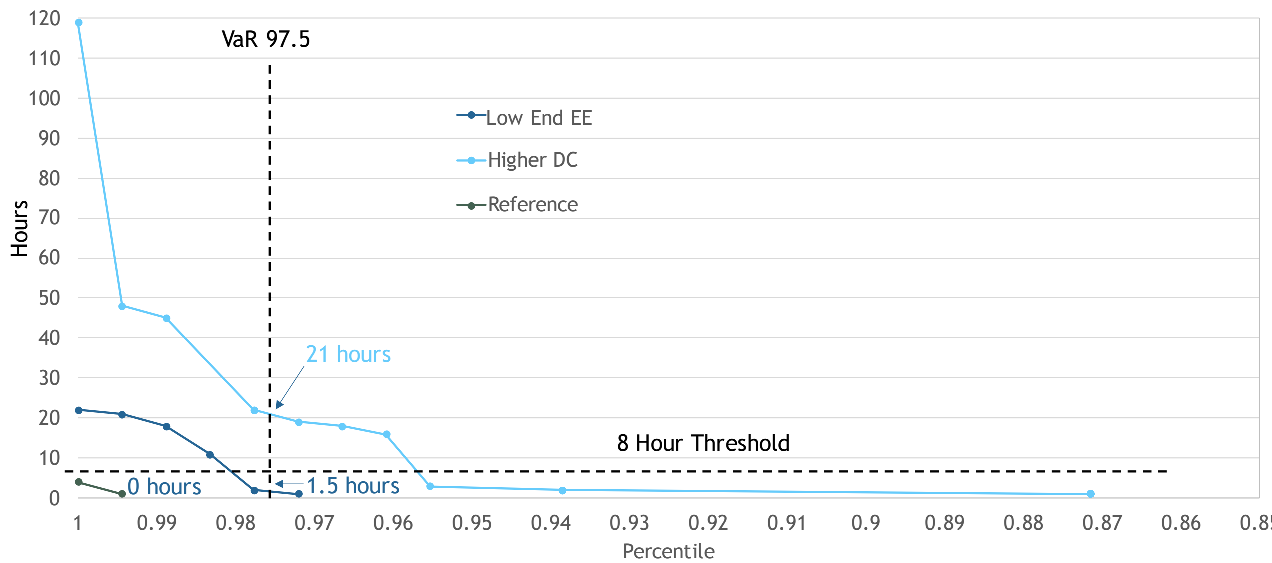


Figure 9. Max duration curves across the scenarios

Aside from the longest duration shortfalls calculated for the metric, considering the distribution of all shortfall durations (Figure 10) highlights that the majority of shortfalls, including in the Low End EE and Higher Data Center scenario, are short. In fact, around ~42% of all shortfalls in both studies are only 1 hour long, and ~70% less than 4 hours.

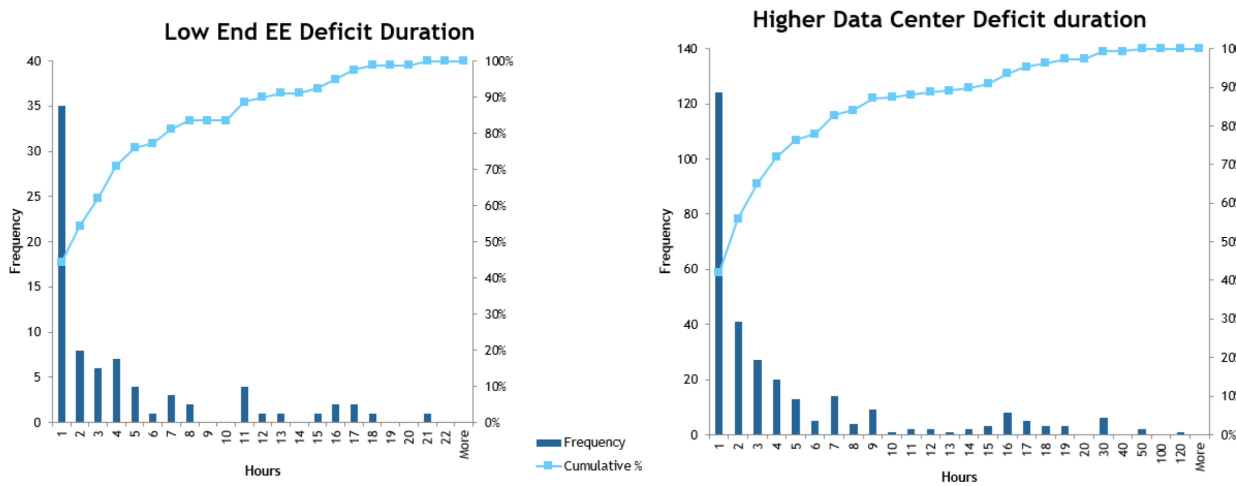


Figure 10. Distribution of shortfall durations in Low End EE and Higher Data Center scenarios

Maximum Peak distribution shows the tail-end magnitude of events, seen in Figure 11. All shortfall peaks in Reference scenario are below the threshold. However, the Low End EE is 367 MW shy of the threshold, and the Higher Data Center is 1,876 MW over. Theoretically, this implies the perfect capacity of needed resources to satisfy this metric, with the guiding principle that the additional resources would lower the curves by those magnitudes. However, this is mentioned as a nod for future analysis and not part of the adequacy assessment given the role is to provide an adequacy signal, not recommend a portfolio.

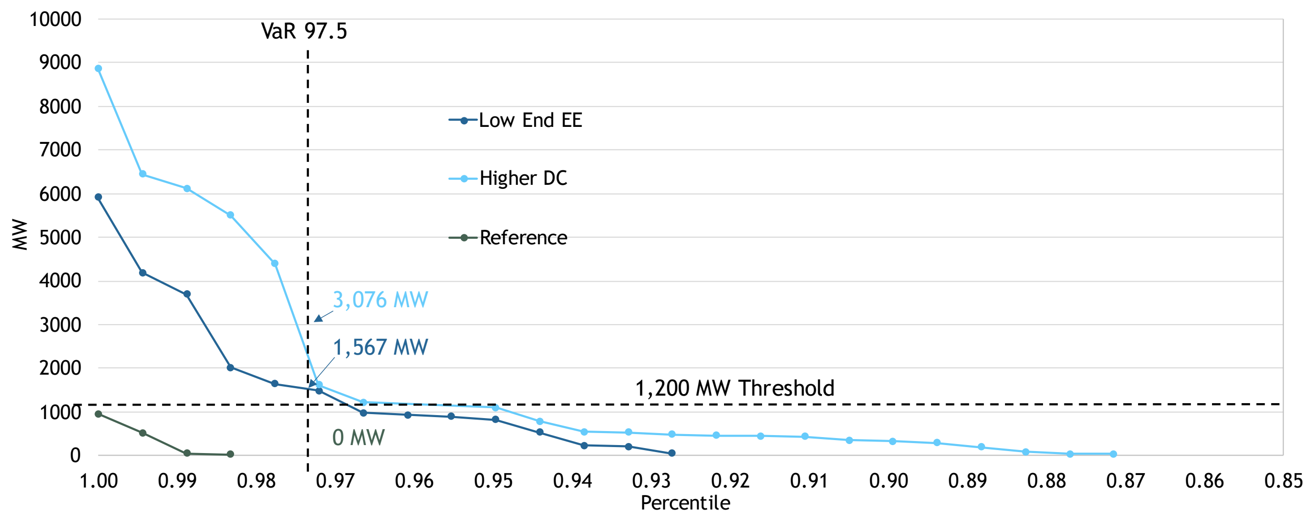


Figure 11. Max peak curves across the scenarios

There is greater diversity of shortfall peaks when considering the full distributions, observed in Figure 12. In both scenarios, around 20% of shortfall peaks are below 300 MW, just over 50% are below 900 MW, and ~68% of shortfalls peaks are below 1,200 MW.

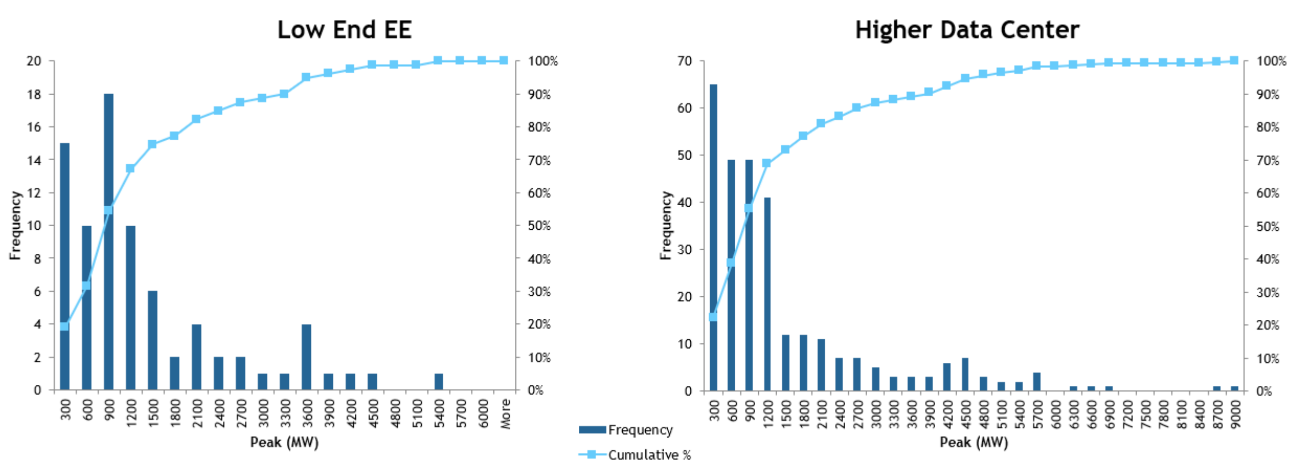


Figure 12. Distribution of shortfall peaks in Low End EE and Higher Data Center scenarios

Reconciling the perceived differences between the Peak VaR metric and curve and the actual peak shortfall distribution is that the fact that only a handful of simulation years (from 180) experienced shortfalls. For example, in the Low End EE scenario, 56 out of the 80 shortfall events are from just 3 simulation years. These specific years are associated with challenging low water conditions throughout the year; coupled with certain renewable wind conditions, this may pose adequacy risks. The same challenging simulation years belong to a broader group of six years. In the Higher Data Center scenario, they account for 220 of the 296 events, with another 52 events clustered in a different set of challenging hydro-load-wind conditions.

The annual Energy curves are provided in Figure 13. The Reference scenario's Energy observations are all below the threshold. And while the Low End EE scenario's Energy VaR is satisfied, there are extreme energy observations beyond the intention of risk protection. The Higher Data Center expands the risk of extreme energy shortfalls, crossing the threshold around the 94.5th percentile.

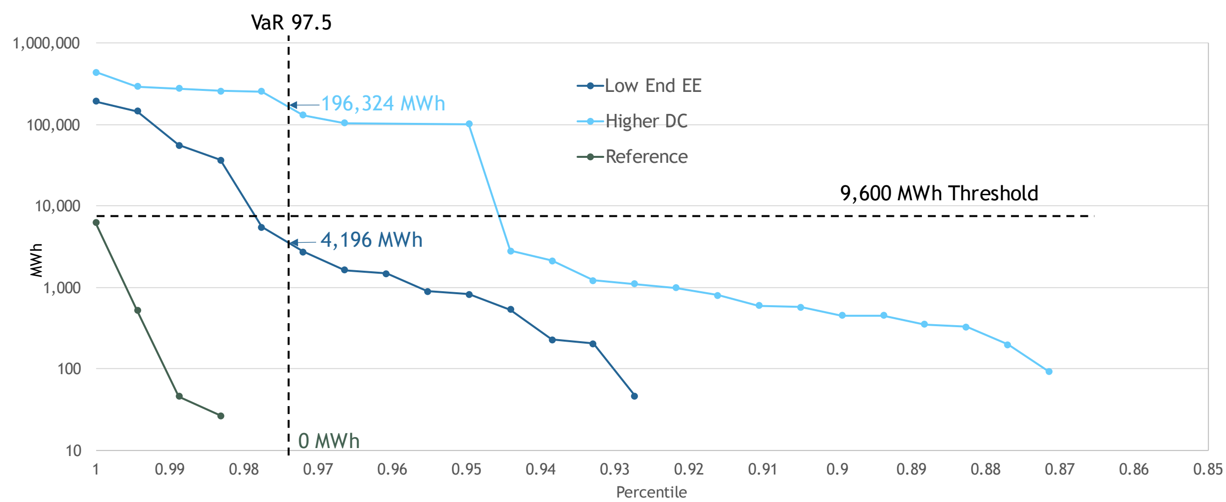


Figure 13. Annual energy curves across the scenarios

Timing of shortfalls

The final section of the results discussion focuses on timing of shortfalls, provided in Figures 14-16. While shortfall timing is not an adequacy metric, evaluating the potential hours of needs throughout each month sheds light on connections to other system stressors. Under the Reference scenario, the handful of shortfalls occurred mostly in winter, with the biggest single event in January during the evening ramp/early night period of 20:00-midnight, seen in the heatmap below; keeping in mind these are very infrequent, with winter LOLEV of 0.022, summer of 0.017 and spring of 0.011.

However, the Low End EE scenario has increased risk of challenges in several periods. The biggest peak shortfalls occur during winter morning and evening ramp hours. A handful of conditions could see shortfalls observed throughout all hours of those days as well. While these shortfalls are still infrequent – they occur more than allowed (winter LOLEV of 0.35, roughly 1 event in 2.85 years) – but are still important to understand. Unlike the reference, there is greater risk of evening/night shortfalls in the spring and summer as well as morning and day in spring (but within the allowed limits). The Higher Data Center scenario further exacerbates similar trends.

While the shoulder seasons – spring and fall - have historically had little adequacy risks, changing system conditions may alter this over time. The risk may still be tied to availability of hydro and earlier runoff coupled with increased loads, but these seasons warrant attention, nonetheless. First, increased loads (whether from higher tech loads or from achieving the low end of energy efficiency) may strain the system during these times in ways similar conditions posed little risk before. Second, because maintenance schedules for hydro and thermal plants are often during spring and fall, these may further coincide with conditions that could pose adequacy challenges. These reasons highlight the benefit of considering the LOLEV frequency metric across all seasons.

Month / Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan																					689	844	960	924
Feb																								
Mar																							46	
Apr																								
May																								359
Jun																								
Jul																			27					525
Aug																								
Sep																								
Oct																								
Nov																								
Dec																								

Figure 14. Reference scenario shortfall timing – peak magnitude (MW) heatmap

Month / Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan		219			620	1394	2524	3855	5346	4414	3431	1220	336	450	768	521	1491	2785	2767	2972	542			413
Feb	726	658	618	612	652	730	1147	3694	1606	835	1223	1026	262	461	936	1200	1643	2162	2681	3455	2798	1259	1714	3511
Mar																								
Apr																							894	609
May						1159		224	347	98						2020	817							1489
Jun																							1426	825
Jul																								230
Aug																				576	635			975
Sep																						533		504
Oct																								
Nov																								
Dec	1184	1571	693	743	1560	2327	3203	4179	5328	5915	3383	3136	2461	2060	2241	2225	1972	3694	5100	4208	3549	2433	67	

Figure 15. Low End EE scenario shortfall timing – peak magnitude (MW) heatmap

Month / Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan	925	900	876	871	894	1146	3986	6117	5586	3963	3684	1726	1558	1431	1433	1326	2121	1910	2759	3043	1501	1022	981	1621
Feb	1144	653	613	607	647	1094	3062	5684	5138	4762	3648	1059	1059	947	888	1303	803	1856	1790	2433	1346			
Mar																		45						1217
Apr														38.439										
May																							69	199
Jun													978			193		550	551	533		208	141	
Jul																				34			368	1026
Aug														278	623	616	1479	1978	1865	1981	1820	539	1277	1680
Sep																								788
Oct																								
Nov																								
Dec	3999	1527	685	697	724	1541	3213	8090	8863	8407	7561	5121	3306	2700	4068	4414	6688	6440	5563	4829	3521	2547	1404	

Figure 16. Higher Data Center scenario shortfall timing – peak magnitude (MW) heatmap

Interpreting multiple metrics

Evaluating the distributions of the metric observations alongside the actual shortfalls has a key role in this assessment – better understanding a multi metric approach with limits on frequency, duration, and magnitude of shortfalls (and therefore emergency measures). As the Reference scenario is adequate, the Low End EE scenario provides a good example to discuss given that duration and energy metrics are satisfied and the frequency and peak metrics are violated. Recall that the while the Peak VaR metric is 367 MW higher than the threshold, only 20% of all shortfall peaks are below 300 MW. In other words, while adding 367 MW of perfect capacity would theoretically satisfy the Peak VaR metric (protect against the tail-end risk 39-in-40 years), it might only mitigate 20% of shortfalls, resulting in LOLEV that still exceeds the threshold. Thus, protecting against a distributional peak doesn't automatically protect against overall frequency of events.

This highlights why (a) all metrics must be satisfied to be deemed adequate, and (b) no metric should be considered the binding metric. Rather, it is possible that the emphasis of risk between frequency, duration, and magnitude will vary by scenario (i.e. future conditions and circumstances). Instead of using the word "binding", another suggestion is the to frame it as which metric needs a larger investment (cost/resources) to mitigate while ensuring all metrics are satisfied. While discussing potential solutions for adequacy challenges is outside the scope of the Council's adequacy assessments, this discussion extends into future Power Plan work.

Conclusion

While the region is facing substantial load growth uncertainty, the 2021 Power Plan resource strategy, with the alleviating circumstances of announced coal-to-gas conversions and expanded transmission capacity, are found to provide an adequate system in the Reference Case. Thus, assuming the Reference Case is the trajectory, continued implementation of the strategy, including ensuring sufficient reserves and acquiring another two years of energy efficiency and renewables, not retiring thermal plants through coal-to-gas conversions, and expanded transmission capacity offset the adequacy challenge of increased loads of anticipated data centers and electric vehicles.

However, achieving the low end of the energy efficiency target offers more risk to maintain regional adequacy. The low end of EE, alongside the resource strategy, does not fully mitigate challenges of increased loads in 2029 despite the alleviating circumstances of not retiring thermal plants and expanded transmission. The risk of shortfall frequency and peak magnitude persist with expectation that shortfalls may occur throughout the days in winter (though greatest magnitudes in morning/evening ramp hours), and additional challenges in spring and summer.

Should tech sector load forecast accelerate, driven by higher data center load, and reach the high end of the trajectories, the region will not be adequate. The ~1,600 MW of increased load associated with additional data center load growth above the reference case causes the scenario to violate all adequacy metrics and trigger larger seasonal challenges.

As the region is facing unprecedented load growth uncertainty driven by data center and transportation electrification, as well as building electrification, the Council will continue tracking and planning for these risk factors in the development of the upcoming Power Plan and the eventual resource strategy to address the evolving needs of the region.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-26-18

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

Exhibit 2-72:
FERC Western Energy Markets Explainer

Western Energy Markets Explainer

This explainer offers a comprehensive overview of the electricity markets in the Western United States. It covers key features of the markets that enable coordinated and efficient management of the region's electric transmission grid system. This explainer will help you understand how new developments in electricity markets in the West may impact energy costs, system reliability, and the implementation and achievement of state-level energy policies.

This explainer is organized with four major sections:

This explainer offers a summary of publicly available information about Western markets and should not be relied upon as a legal document.

Key Terms

Balancing Authorities oversee electricity transfers and ensure grid stability by maintaining a balance between the production and consumption of electricity. They typically oversee long-term efforts to maintain that key balance on the grid, such as resource planning, as well as short-term balancing by committing electricity supply resources to operate and real-time load-frequency control within a balancing authority area. Certain electric utilities and power marketing administrations (see below) are typical examples of balancing authorities.

A **Balancing Authority Area** is a geographic region that incorporates a collection of generation facilities, transmission lines, and loads (aggregated consumer demand for electricity) where electric metering is performed by a balancing authority. The responsibility of maintaining a balance between the load and resources (supply of electricity) within this area falls under the jurisdiction of the balancing authority. One example of a balancing authority area is a utility service territory.

Congestion occurs when a portion of the transmission grid becomes overloaded with electricity. Congestion can occur when a line or transformer reaches its limit and cannot carry any more electricity. When congestion occurs, the lowest-priced electricity cannot flow freely to a specific area.

Congestion Revenue Rights are financial tools used to manage the cost variability of congestion on the grid based on the electricity pricing approach used, called locational marginal pricing (see below). Such rights are often acquired to hedge against congestion costs in the day-ahead market, but sometimes are purchased as an investment.

A **Day-Ahead Market** is a voluntary financial market where individuals and companies can buy and sell wholesale electric energy at financially binding prices for the next day.

Hedging is the act of engaging in transactions to reduce risk from price volatility (see below) for a company and/or customers. Hedging transactions can help electricity suppliers meet their customers' demands while reducing or eliminating the risk of fluctuating prices.

Locational Marginal Pricing or Prices (LMP) refer, respectively, to the overall pricing scheme or the actual prices paid for wholesale electric energy at a specific location within an electric transmission grid at a specific point in time. LMP data is used to track the prices of electricity in different parts of the grid and to help manage supply and demand for electricity.

Price Volatility describes how quickly or widely prices can change. In the energy industry, price volatility can refer to electricity or natural gas supply prices, relative to consumer demand. Volatility is measured by the day-to-day variation (percentage difference) in the price of the commodity.

A **Power Marketing Administration** is a federal agency within the Department of Energy that markets electric power produced by federal dams and multiple-purpose water projects providing service to customers.

A **Real-Time Energy Market** is a spot market that allows consumers, companies, and energy distribution businesses to buy and sell wholesale electric energy in real-time, usually an hour before delivery. The real-time market balances the differences between day-ahead resource commitments and demand forecasts and the actual real-time demand for and production of electricity.

Resource Adequacy is the ability of an electric transmission grid to meet consumer demand for power. Resource adequacy ensures that there is enough energy generating capacity and reserves to maintain a balanced supply and demand across an electric system.

Wholesale Electric Energy, also referred to as wholesale electricity, is electric energy that is purchased or sold for resale, whereas retail electric energy is electric energy that is purchased by or sold to the ultimate consumer.

California ISO Extended Day-Ahead Market is a voluntary day-ahead electricity market designed to deliver significant reliability, economic, and environmental benefits to balancing areas and utilities throughout the West. The initial structure of EDAM was approved, in most part by the Commission in December 2023.

Introduction

In the U.S., the power grid is a complex network of power plants and transmission lines with extra-high-voltage connections between utilities. This expansive infrastructure allows the movement of electricity from one part of the network to another.[1] Over time, the U.S. power grid has evolved into three large interconnected systems, which are shown in Figure 1:

1. the Eastern Interconnection that operates in states east of the Rocky Mountains
2. the Western Interconnection that covers the Pacific Coast to the Rocky Mountain states
3. the Texas Interconnected System, known as ERCOT

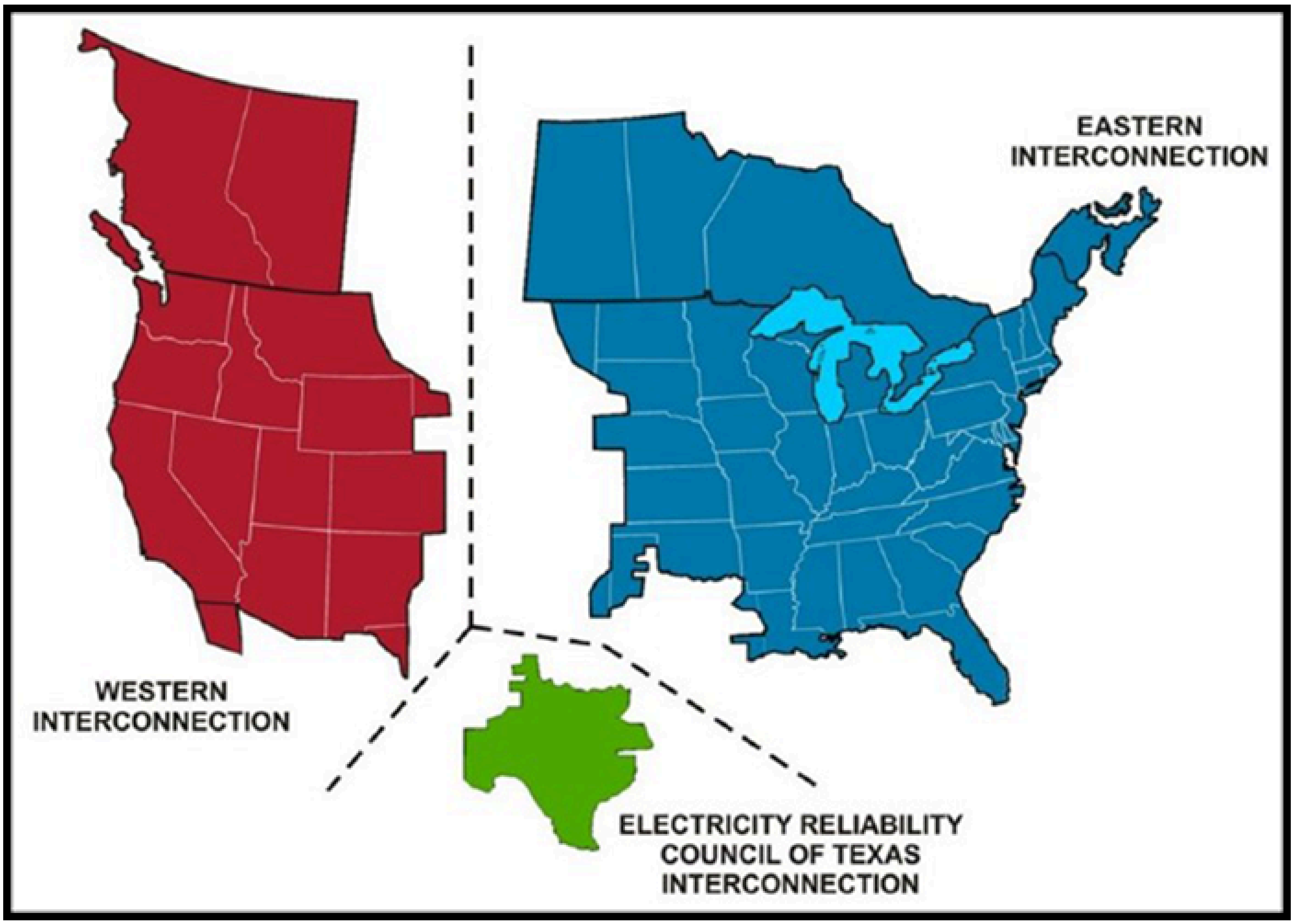


Figure 1. The Three Major Interconnections of the U.S. Electric Power Grid. Source: North American Electric Reliability Corporation.

The electric grid must comply with standards developed by the North American Electric Reliability Corporation (NERC) to ensure reliability of the grid. Because these three systems encompass unique geographic areas, NERC also assigns responsibilities to six regional entities who apply standards and act as compliance authorities. In the Western Interconnection, the Western Electricity Coordinating Council (WECC) is the regional entity, which oversees bulk power system reliability and security in the region. [2]

In the late 1990s, FERC initiated significant reforms in the electricity sector to support competition in the energy marketplace. The milestones included:

- Order No. 888 (1996): established the foundation for organized wholesale markets by promoting independent system operators (ISOs).[3] These entities were designed to foster competition among electricity generators at the wholesale level.
- Order No. 2000 (1999): encouraged utilities to join regional transmission organizations (RTOs). The aim was to enhance the operation of transmission systems and to develop equitable transmission management practices.[4]

Today, RTOs and ISOs play a crucial role in electricity policy. They serve approximately two-thirds of U.S. electricity consumers, managing both power markets and regional transmission systems (Figure 2 shows the boundary areas the RTO and ISO regions).[5]

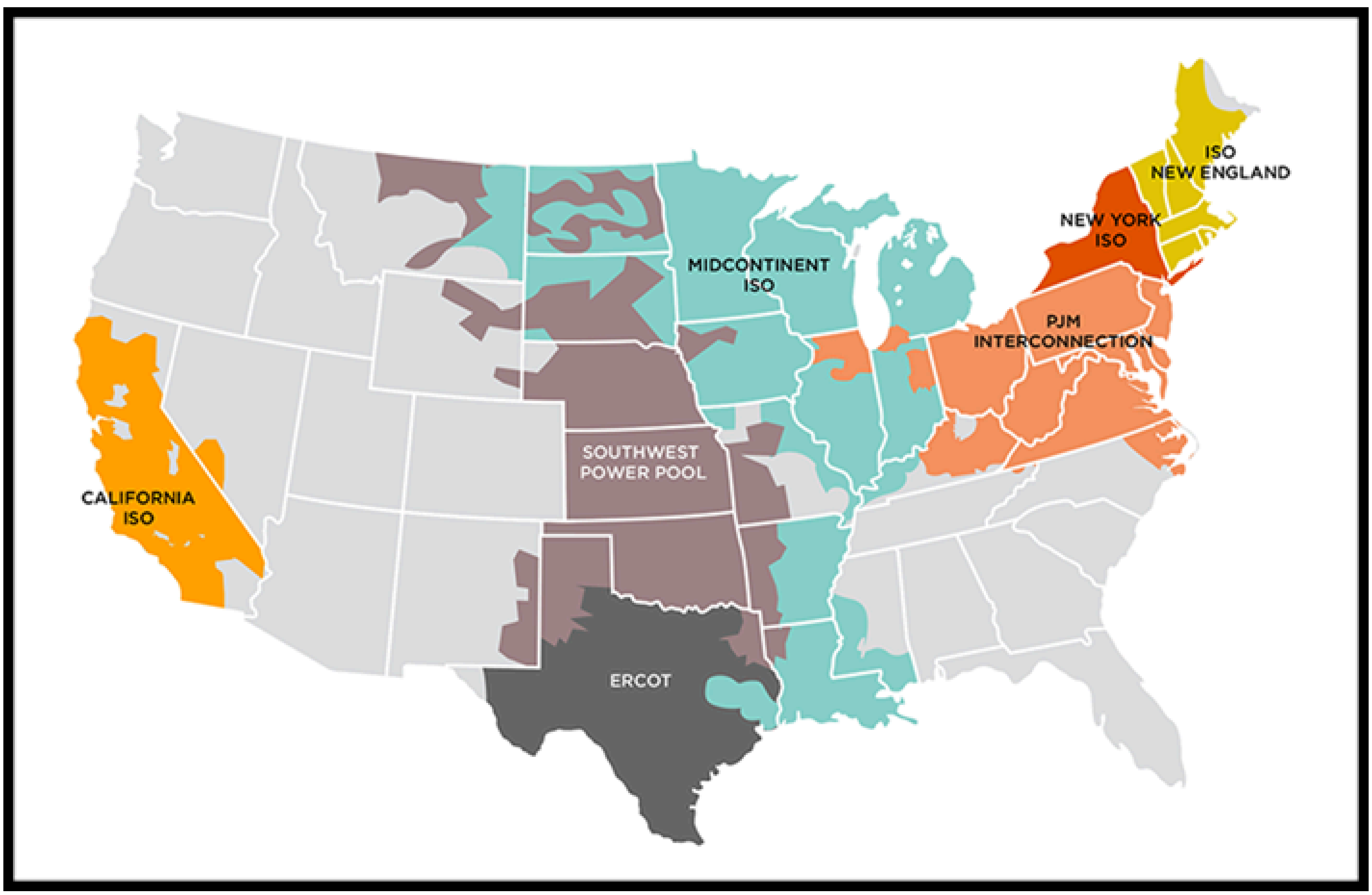


Figure 2. Seven RTO and ISO Regions in the Continental United States.

The West has progressively developed its regional wholesale electricity markets, adopting new systems and improvements step-by-step. Unlike other regions that may implement large-scale changes all at once, the West has chosen to evolve its electricity markets gradually, with each stage of development building upon the last.[6] For example, a single organized market manages energy trades for most of California—the California Independent System Operator (CAISO)—and there are currently no multistate RTOs (although, as seen in Figure 2, CAISO territory includes a small area of Nevada).[7]

The West uses a coordinated system of regional real-time energy supply markets and bilateral trading between a specified buyer and a specified seller of electricity. The Western Area Power Administration and the Bonneville Power Administration, two Western Power Marketing Administrations within the Department of Energy, sell electric power produced by federal dams to utilities (Figure 3 shows the boundary areas of the four Power Marketing Administrations).

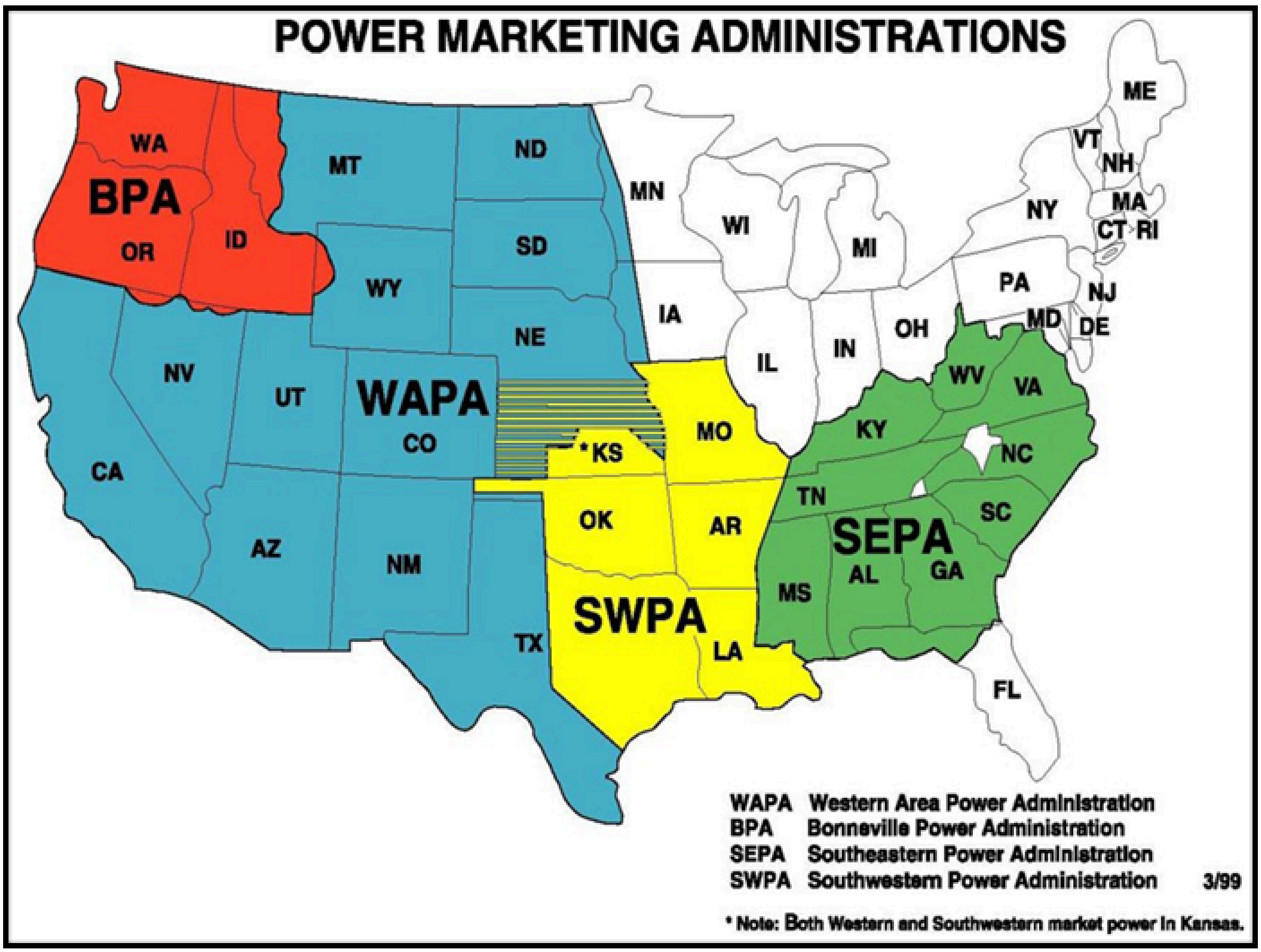


Figure 3. Power Marketing Administrations in the Continental United States. Source: SPP

While CAISO is currently the only ISO in the West, FERC has approved several market initiatives in the last twenty years that have led to a more integrated Western electric system that encompasses several Western states. The rest of this explainer will discuss CAISO as well as other initiatives and entities that contribute to the region's electricity landscape.

Overview of Electricity Markets in the West

California Independent System Operator (CAISO)

Figure 4. California Independent System Operator (CAISO) area.

The California Independent System Operator (CAISO)[8] was founded in 1998 and became a fully functioning ISO in 2008. CAISO manages the flow of electricity across the high-voltage, long-distance power lines serving 80% of California and a part of Nevada (Figure 4 shows the boundary areas of CAISO).[9]

CAISO provides open access to the transmission lines it operates and performs long-term transmission planning. In managing the grid, CAISO centrally dispatches generation and coordinates the movement of wholesale electricity in the area shown. CAISO's wholesale energy markets comprise day-ahead and real-time processes that include energy products, such as real-time energy, day-ahead energy, ancillary services, and congestion revenue rights. The Commission also approved, in most part, CAISO's Extended Day-Ahead Market proposal in December 2023.

Western Energy Imbalance Market (WEIM)

In 2014, CAISO initiated the Western Energy Imbalance Market (WEIM) with the purpose of expanding real-time market access to utilities in the Western Interconnection who are not members of CAISO. Utilities participating in the WEIM include utilities and balancing authorities outside of CAISO's territory. Among other benefits, the WEIM provides its participants with access to least-cost electricity across the region. There are also operational and reliability benefits to the sharing of electricity through WEIM. For example, when one part of the West is experiencing an electric energy shortage while others are not, there can be sales of excess electric energy to the area that needs it.

Concerning day-to-day operations, the WEIM is a real-time energy market that allows participating utilities to balance their supply and demand within 15 minutes or 5 minutes of delivery using the least-cost resources available across a wider footprint, helping to manage system needs. This creates a coordinated system of regional real-time energy supply markets, which, while not a full RTO or ISO, offers a structured approach to energy trading and system balancing in the West.

Since the WEIM began offering real-time market access to utilities outside of CAISO's territory, the WEIM has grown to serve parts of Arizona, California, Idaho, Montana, Nevada, New Mexico, Oregon, Texas, Utah, Washington, and Wyoming, and extends to the border with Canada and Mexico, totaling 22 participating entities representing 79% of the energy load in the WECC.[10] The WEIM's ability to leverage CAISO's market optimization tools to service the needs of the utilities outside its ISO structure have led to reported cost-savings.[11] Presently, the WEIM claims to have delivered more than $5 billion in benefits by connecting a broader area with access to lower-cost electricity.[12]

The WEIM is governed by a five-member body with shared authority from the CAISO Board of Governors on rules specific to participation in the WEIM.[13] As designed by regional stakeholders, the WEIM Governing Body is nominated by a committee of Western stakeholders. The WEIM Governing Body and CAISO Board of Governors frequently hold public sessions that include a toll-free number for members of the public to listen to the meeting. These public sessions include opportunities for public comment following briefings on policy initiatives as well as WEIM benefits and market updates.

Southwest Power Pool (SPP)

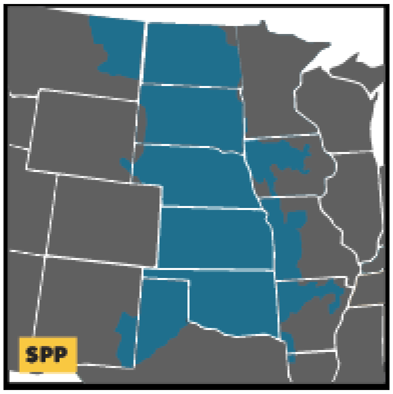


Figure 5. Southwest Power Pool (SPP) area.

The Southwest Power Pool (SPP), an RTO operating primarily in the Midwest, operates energy markets in both the Eastern and Western interconnections. Founded in 1941 as an 11-member power pool that allowed for power sharing among participating utilities, SPP achieved RTO status in 2004. Based in Little Rock, Arkansas, SPP manages transmission in portions of fourteen states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. Its membership comprises investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, independent power producers, power marketers, and independent transmission companies.

In 2015, SPP's footprint expanded when the Western Area Power Administration—Upper Great Plains (WAPA-UGP) region, the Basin Electric Power Cooperative, and the Heartlands Consumer Power District—joined the RTO. The expansion nearly doubled SPP's service territory and added more than 5,000 MW of peak demand and over 7,000 MW of generating capacity. WAPA-UGP is the first federal power marketing administration to join an RTO.

In January 2025, FERC also approved, subject to condition, SPP's Markets+ proposal.

Additionally, in March 2025, FERC approved, subject to condition, SPP's RTO West proposal.

Western Energy Imbalance Service (WEIS) Market

In 2020, SPP established the Western Energy Imbalance Service (WEIS) market with the purpose of providing real-time market access to utilities in the Western Interconnection who are not members of the SPP RTO. Like CAISO's WEIM, SPP's WEIS seeks to provide participants with access to least-cost electric energy and to create reliability and operational advantages, such that power from areas with excess electric energy can flow to an area experiencing a shortage (such as during a weather emergency).

WEIS centrally dispatches generation to balance supply and demand in real-time and allows parties to continue to trade wholesale electricity bilaterally. Additionally, the WEIS has a goal of allowing participants to hedge against transmission congestion while coordinating the movement of wholesale electricity. In 2022, according to the WEIS Benefit of Market Report, WEIS claims to have provided $31.7 million in net benefits to its 12 participating Western utilities.[14]

SPP's independent Board of Directors provides ultimate oversight of the WEIS's administration; however, the Western Markets Executive Committee is responsible, through its designated working groups, committees, and task forces, for developing and recommending policies, procedures, and system enhancements related to the administration of the WEIS by SPP under the Western Joint Dispatch Agreement in the Western Interconnection.[15] In coordination with the Western Markets Executive Committee, the Western Markets Working Group provides a public forum for customers to engage in matters of governance and strategy with other stakeholders.[16] In 2024, all Western Markets Executive Committee meetings will be joint with the Western Markets Working Group. Members of the public may register on www.SPP.org for these meetings and attend in-person or by phone.

Western Power Pool (WPP)

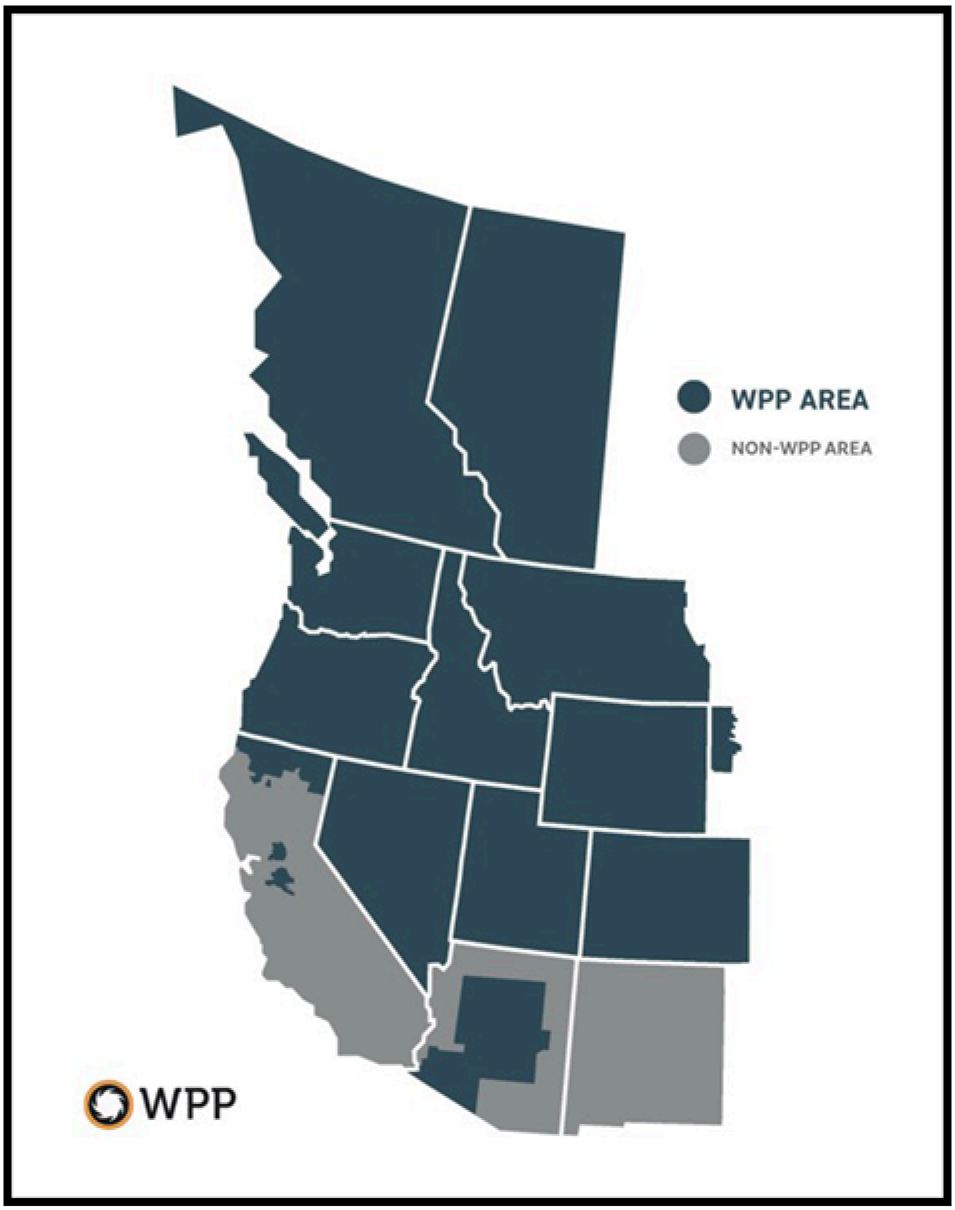


Figure 6. Western Power Pool (WPP) area. Source: WPP

The Western Power Pool (WPP), previously known as the Northwest Power Pool, is a group of utilities and other entities that coordinate and share resources in the Western Interconnection (Figure 6 shows the boundary areas of WPP). The WPP provides services to its members, such as transmission planning and tariff administration.[17] The WPP was formed in 1983 to promote increased efficiency, competition, and coordination in the electric power industry.[18] The WPP is governed by a Board of Directors, a Governing Body, and various committees and working groups that represent the interests of its members and stakeholders. The WPP also collaborates with other regional entities, such as the WECC, SPP, and CAISO, to enhance the reliability and efficiency of the Western Interconnection. While the WPP does not provide transmission service and is not an RTO/ISO, it does provide significant benefits by ensuring reliable energy capacity and reserves across the electric system.

To that end, in August 2022, the WPP filed at FERC the Western Resource Adequacy Program (WRAP) proposal, in Docket No. ER22-2762, which is intended to enhance resource adequacy. Resource adequacy ensures that there is enough energy capacity and reserves to maintain a balanced supply and demand across the electric system.[19] The WRAP was approved by FERC in February 2023 and is expected to launch in mid-2025.[20]

Western Resource Adequacy Program (WRAP)

The WRAP is not an organized market like CAISO's WEIM or SPP's WEIS but is instead a program WPP runs to ensure that the electricity supply in the West can meet the demand and reliability needs of customers. When implemented, the WRAP will have two main components: (1) a forward showing program, where participants demonstrate their ability to meet their peak demand plus a reserve margin for the next year; and (2) an operations program, where participants monitor and report their daily resource availability and demand as well as comply with dispatch instructions from the program operator. SPP acts as the program operator and, as directed by WPP, provides services for the WRAP, such as modeling, analytics, real-time operations, and technical improvement.

The WRAP is designed to be compatible with existing markets and programs in the West, such as the WEIM and the CAISO markets. The WRAP is also open to area participants who want to join the program and benefit from its regional approach. The WRAP seeks to help participants address the challenges of resource adequacy in the West in a manner consistent with state goals, such as increasing demand, retiring coal plants, and integrating variable renewable energy sources.[21]

To Learn More

Additional information on the topics discussed is available on FERC's website, including the FERC rulings cited in this explainer, the 2024 Energy Primer, as well as on the:

- CAISO website
- SPP website
- WPP website

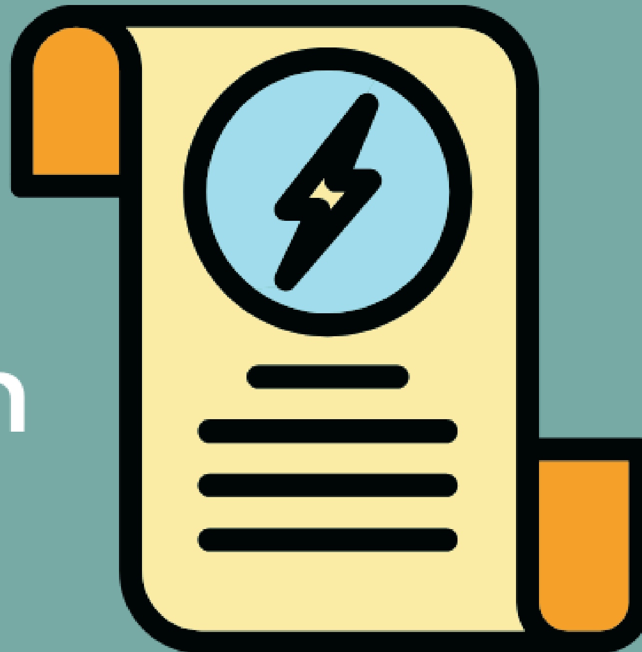
In addition to the existing markets and programs discussed above, the Western area markets may continue to develop and change. To follow FERC matters relevant to the expansion of the Western markets, you may:

- Subscribe to the Office of Public Participation (OPP) newsletter;
- Follow stakeholder processes with the stakeholder centers of CAISO and SPP; and
- eSubscribe to electronically receive information related to a particular FERC docket or set of dockets in which you have an interest.

OPP is dedicated to helping the public understand and participate in FERC proceedings. Members of the public can contact OPP for assistance in navigating FERC proceedings and receiving information on when and how to comment, intervene, or file motions during proceedings.

Please contact OPP by e-mail at OPP@ferc.gov, by phone at (202) 502-6595, or see our website at www.FERC.gov/OPP for additional information and resources.

Western Markets Expansion



CAISO

Order No. 2000

CAISO ISO Open Access Transmission Tariff (OATT)

Western Energy Imbalance Market WEIM (CAISO)

147 FERC ¶ 61,231 (2014)

Docket No. ER14-1386

EIM Section to CAISO OATT

Western Energy Imbalance Service WEIS (SPP)

173 FERC ¶ 61,267 (2020)

Docket Nos. ER21-3/ER21-4

WEIS OATT

Western RA program WRAP (Western Power Pool)

182 FERC ¶ 61,063

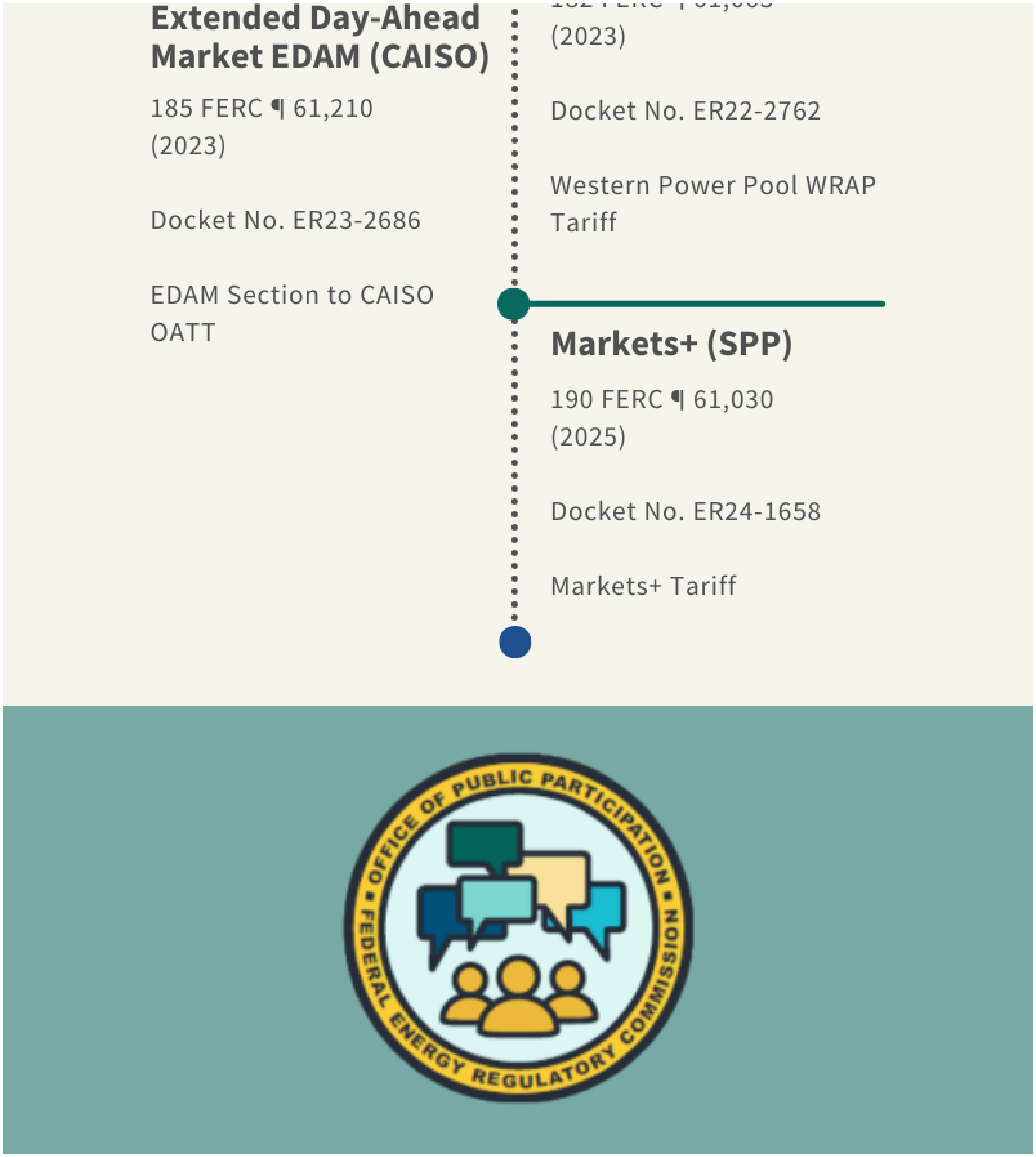


Figure 7. Western Markets Expansion infographic.

[1] Transmission Agency of Northern California. https://www.tanc.us/understanding-transmission/the-western-us-power-system.

[2] Specifically, FERC mandated NERC to oversee the reliability of the bulk power system, which includes parts of Mexico and Canada. For further information, see the Office of Public

Participation's Reliability Primer. https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[3] Electricity Markets Explainer. https://www.ferc.gov/introductory-guide-electricity-markets-regulated-federal-energy-regulatory-commission.

[4] Order 2000 can be viewed at: https://www.ferc.gov/sites/default/files/2020-06/RM99-2-00K_1.pdf.

[5] Electric Power Markets. https://www.ferc.gov/electric-power-markets.

[6] A description of the history and motivating factors for market developments in the West: https://www.rabobank.com/knowledge/d011408934-no-rto-no-problem-rethinking-regulated-markets-in-the-us-electricity-heartland.

[7] In the case of CAISO, the ISO has chosen not to seek RTO status. RTOs are electric power transmission system operators that coordinate, control, and monitor a multistate electric grid. ISOs are like RTOs, which also coordinate, control, and monitor the operation of the electrical power system. However, ISOs cover geographic areas within a state or a smaller region.

[8] Understanding and Participating in CAISO Processes. https://www.ferc.gov/understanding-and-participating-california-iso-caiso-processes.

[9] CAISO. http://www.caiso.com/about/Pages/OurBusiness/Default.aspx.

[10] CAISO. https://www.westerneim.com/Documents/weim-first-quarter-benefits-for-2023-reach-418-million.pdf.

[11] A description of the history and motivating factors for market developments in the West: https://www.rabobank.com/knowledge/d011408934-no-rto-no-problem-rethinking-regulated-markets-in-the-us-electricity-heartland.

[12] WEIM. https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

[13] WEIM. https://www.westerneim.com/Pages/Governance/GoverningBody.aspx.

[14] SPP. https://spp.org/western-services-documents/?id=371676.

[15] SPP. https://spp.org/documents/61046/wmec%20charter%2020221018.pdf.

[16] SPP. https://spp.org/western-services/weis/.

[17] Western Power Pool. https://www.westernpowerpool.org/private-media/documents/WPP_WRAP_Interoperability_with_Markets_June_2023.pdf.

[18] Western Power Pool. https://www.westernpowerpool.org/.

[19] CAISO. https://www.caiso.com/Documents/Resource-Adequacy-Fact-Sheet.pdf.

[20] *Northwest Power Pool*, 182 FERC 61,063 at P 13-14 (2023).

[21] Western Power Pool. https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program.

Quick Links

- Introduction to Western Markets Expansion

Contact Information

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Telephone: 202-502-6595
Email: OPP@ferc.gov

This page was last updated on April 18, 2025

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-26-18

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

Exhibit 2-73:
Bonneville 2024 Fact Sheet

BPA Facts

INFORMATION IS FOR FISCAL YEAR 2024, UNLESS OTHERWISE NOTED.

Profile

The Bonneville Power Administration is a nonprofit federal power marketing administration based in the Pacific Northwest. Although BPA is part of the U.S. Department of Energy, it is self-funding and covers its costs by selling its products and services. BPA markets wholesale electrical power from 31 federal hydroelectric dams in the Northwest, one nonfederal nuclear plant and several small nonfederal power plants. The dams are operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation. The nonfederal nuclear plant, Columbia Generating Station, is owned and operated by Energy Northwest, a joint operating agency of the state of Washington.

BPA provides about one-third of the electric power generated in the Northwest, primarily from reliable, dispatchable and flexible hydroelectric resources. BPA also operates and maintains more than 15,000 circuit miles of high-voltage transmission in its service territory. BPA's territory includes Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah and Wyoming.

BPA promotes energy conservation and innovative technologies that improve its ability to deliver on its mission. To mitigate the impacts of the federal dams, BPA implements a fish and wildlife program that includes working with its partners to make the federal dams safer for fish passage.

BPA is committed to public service and seeks to make decisions in a manner that provides opportunities for input from all interested parties. In its vision statement, BPA dedicates itself to providing high system reliability, low rates consistent with sound business principles, environmental stewardship and accountability.

Mission

BPA's mission as a public service organization is to create and deliver the best value for our customers and constituents as we act in concert with others to assure the Pacific Northwest:

- An adequate, efficient, economical and reliable power supply.
- A transmission system that is adequate to the task of integrating and transmitting power from federal and non-federal generating units, providing service to BPA's customers, providing interregional interconnections, and maintaining electrical reliability and stability.
- Mitigation of the impacts on fish and wildlife from the federally owned hydroelectric projects from which BPA markets power.

BPA is committed to cost-based rates, and public and regional preference in its marketing of power. BPA sets its rates as low as possible consistent with sound business principles and the full recovery of all of its costs, including timely repayment of the federal investment in the system.

Core values

SAFETY

We value safety in everything we do. Together, our actions result in people being safe each day, every day. At work, at home and at play, we all contribute to a safe community for ourselves and others.

TRUSTWORTHY STEWARDSHIP

As stewards of the Federal Columbia River Power System, we are entrusted with the responsibility to manage resources of great value for the benefit of others. We are trusted when others believe in and are willing to rely upon our integrity and ability.

COLLABORATIVE RELATIONSHIPS

Trustworthiness grows out of a collaborative approach to relationships. Internally we must collaborate across organizational lines to maximize the value we bring to the region. Externally we work with many stakeholders who have conflicting needs and interests. Through collaboration we discover and implement the best possible long-term solutions.

OPERATIONAL EXCELLENCE

Operational excellence is a cornerstone of delivering on our vision (system reliability, low rates, environmental stewardship and regional accountability) and will place us among the best electric utilities in the nation.

General information

BPA established	1937
Service area size (square miles)	300,000
Pacific Northwest population	14,735,345
Transmission line (circuit miles)	14,973
BPA substations	258
Employees (FTE)[1]	3,191

1/ As of October 2025.

Customers

Cooperatives	53
Municipalities	42
Public utility districts	28
Federal agencies	7
Investor-owned utilities	6
Direct-service industries	1
Port districts	1
Tribal utilities	3
Total	141
Marketers (power and transmission)[1]	165
Transmission customers	415

Rates

Wholesale power rates[2] (fiscal years 2024–2025)

Priority Firm Tier 1 (AVERAGE[3], UNDELIVERED)	3.47 cents/kWh
Priority Firm Avg. Tier 1 + Tier 2 (UNDELIVERED)	3.58 cents/kWh
Priority Firm Exchange (AVERAGE, UNDELIVERED)	7.50 cents/kWh
Industrial Firm (AVERAGE, UNDELIVERED)	4.14 cents/kWh
New Resources (AVERAGE, UNDELIVERED)	8.54 cents/kWh

2/ The rates shown do not include the cost of transmission. They also do not include the impact of the Reserves Distribution Clause.
3/ The actual rate paid by an individual customer will vary according to the shape of the load and the products and services purchased.

Transmission rates[4] (fiscal years 2024–2025)

Network rates	
Long-Term Firm	$1.648/kW-month
Short-Term	0.474 cents/kWh
Southern Intertie rates	
Long-Term Firm	$1.118/kW-month
Short-Term	1.029 cents/kWh

4/ Reflects the rates for point-to-point transmission service. All short-term firm and nonfirm rates are downwardly flexible.

Financial highlights[5]

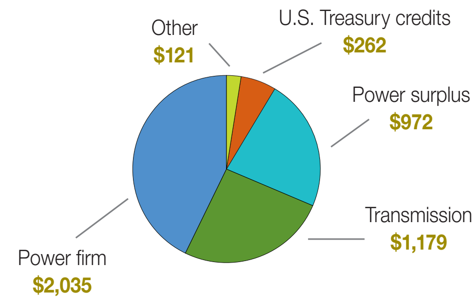
For the Federal Columbia River Power System
($ in millions)

Total operating revenues[6]	$4,569
Total operating expenses	4,357
Net operating revenues	212
Total interest expense and other income, net	344
Net revenues	$ (132)

5/ This information is consistent with BPA's 2024 Annual Report.
6/ For additional information, please visit the 2024 Annual Report at bpa@gov.

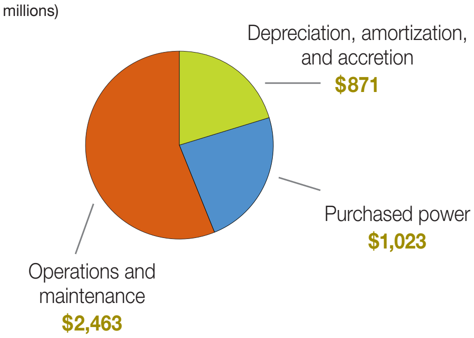
Disaggregated revenues

($ in millions)



Operating expenses[7]

($ in millions)



7/ All intracompany and intercompany accounts and transactions have been eliminated from the FCRPS financial statements.

Transmission system

Operating voltage	Circuit miles
1,100 kV	1.3
1,020 kV	264.3[8]
500 kV	4,734.0
345 kV	569.8
287 kV	0.7
230 kV	5,541.3
161 kV	119.3
138 kV	61.1
115 kV	3,524.3
below 115 kV	157.1
Total[9]	14,973.2

8/ BPA's portion of the PNW/PSW direct-current intertie. The total length of this line from The Dalles, Oregon, to Los Angeles, California is 846 miles.
9/ Total circuit miles as of August 2025.

Federal hydro projects

Name	River, state	In service	Max capacity
Albeni Falls	Pend Oreille, ID	1955	49 MW
Anderson Ranch	*Boise, ID*	*1950*	*40 MW*
Big Cliff	N. Santiam, OR	1953	23 MW
Black Canyon	*Payette, ID*	*1925*	*10 MW*
Boise River Diversion	*Boise, ID*	*1912*	*3 MW*
Bonneville	Columbia, OR/WA	1938	1,216 MW
Chandler	*Yakima, WA*	*1956*	*12 MW*
Chief Joseph	Columbia, WA	1958	2,614 MW
Cougar	McKenzie, OR	1963	29 MW
Detroit	N. Santiam, OR	1953	126 MW
Dexter	Middle Fork Willamette, OR	1954	17 MW
Dworshak	Clearwater, ID	1973	460 MW
Foster	S. Santiam, OR	1967	23 MW
Grand Coulee[10]	*Columbia, WA*	*1942*	*7,049 MW*
Green Peter	S. Santiam, OR	1967	92 MW
Green Springs	*Emigrant Crk, OR*	*1960*	*17 MW*
Hills Creek	Middle Fork Willamette, OR	1962	35 MW
Hungry Horse	*Flathead, MT*	*1953*	*428 MW*
Ice Harbor	Snake, WA	1962	695 MW
John Day	Columbia, OR/WA	1971	2,484 MW
Libby	Kootenai, MT	1975	605 MW
Little Goose	Snake, WA	1970	932 MW
Lookout Point	Middle Fork Willamette, OR	1953	138 MW
Lost Creek	Rogue, OR	1977	56 MW
Lower Granite	Snake, WA	1975	932 MW
Lower Monumental	Snake, WA	1969	932 MW
McNary	Columbia, OR/WA	1952	1,127 MW
Minidoka	*Snake, ID*	*1909*	*28 MW*
Palisades	*Snake, ID*	*1958*	*176 MW*
Roza	*Yakima, WA*	*1958*	*13 MW*
The Dalles	Columbia, OR/WA	1957	2,052 MW
Total (31 dams)			22,391 MW

Owned and operated by the U.S. Army Corps of Engineers (21 dams, 14,637 MW)
Owned and operated by the Bureau of Reclamation (10 dams, 7,776 MW)
10/ Includes pump generation.

BPA resources[11]

(for operating year 2024 under firm water conditions)

Sustained 120-hour peak capacity (January)	13,458 MW
Hydro	11,828 MW (88%)
Nuclear	1,178 MW (9%)
Firm contracts and other resources	452 MW (3%)
Wind	0 MW (0%)

Firm energy (12-month annual avg.)	8,038 aMW
Hydro	6,662 aMW (83%)
Nuclear	1,116 aMW (14%)
Firm contracts and other resources	227 aMW (3%)
Wind	33 aMW (<1%)

11/ The Resource Program provides analysis and insight into long-term, least-cost power resource acquisition strategies.

Regional resources[12]

(for operating year 2024 under firm water conditions)

Sustained 120-hour peak capacity (January)	40,202 MW
Hydro	24,046 MW (60%)
Natural gas	6,288 MW (16%)
Coal	4,195 MW (10%)
Cogeneration	3,179 MW (8%)
Nuclear	1,178 MW (3%)
Imports	1,065 MW (3%)
Other Renewables	182 MW (<1%)
Wind	0 MW (<0%)
Other miscellaneous resources	31 MW (<1%)

Firm energy (12-month annual avg.)	28,382 aMW
Hydro	12,081 aMW (43%)
Natural gas	5,373 aMW (19%)
Coal	3,751 aMW (13%)
Cogeneration	2,737 aMW (10%)
Wind	2,200 aMW (8%)
Nuclear	1,116 aMW (4%)
Imports	588 aMW (2%)
Other renewables	159 MW (<1%)
Solar	352 aMW (<1%)
Other miscellaneous resources	26 aMW (<1%)

12/ Forecast figures from BPA's "2024 Pacific Northwest Loads & Resources Study," tables 2–6, 2–7, 3–3. Firm resource projections before adjustment for reserves, maintenance and transmission losses. The hydro capacity is reduced by an operational "idle capacity" adjustment to estimate the monthly maximum operational capability that is available to meet the 120-hour peak load for firm water conditions.

Federal generation

Hydro generation	6,244 aMW
Total generation	7,392 aMW
60-min. hydro peak generation	11,121 MW
60-min. total peak generation	12,239 MW
All-time 60-min. total peak generation record (June 2002)	18,139 MW

Fish and wildlife

($ in millions)

BPA F&W program expense	$272.2
Direct funded expenditures	103.8
Interest, depreciation and amortization expenses	101.2
Total direct costs	$477
Operational costs:	
Replacement power purchases	856.2
Estimated forgone power revenues	36.6
Total F&W costs for FY 2024[13]	$1,370

13/ Program expenses include integrated program and action plan/high priority. Totals may not equal sum of components due to rounding.

Energy efficiency[14]

	FY 2024	Total[15]
Residential programs	7.5 aMW	563.7 aMW
Commercial programs	6.9 aMW	466.7 aMW
Industrial programs	10.3 aMW	363.9 aMW
Agricultural programs	1.6 aMW	77.0 aMW
Multi-sector programs	0 aMW	108.9 aMW
Federal	1.3 aMW	22.8 aMW
Utility distribution system	0.2 aMW	11.3 aMW
Improved building codes	0 aMW	188.5 aMW
NEEA[16] Net Market Effects	7.8 aMW	371.3 aMW
Momentum Savings[17]	TBD	359.7 aMW
Total aMW saved[18]	35.6 aMW	2,533.8 aMW

14/ All figures are preliminary and subject to final revision.
15/ Cumulative total, FY1982–2024.
16/ Northwest Energy Efficiency Alliance.
17/ Momentum Savings are updated at the end of each Power Planning period. Totals reflect achievements made through the 6th Power Plan.
18/ Data aligns with 2024 Annual Review and may be adjusted from past versions of BPA Facts.

Points of contact

GENERAL BPA OFFICES AND WEBSITES

BPA Headquarters 905 N.E. 11th Ave., P.O. Box 3621, Portland, OR 97208; 503-230-3000; *www.bpa.gov*

BPA Visitor Center 905 N.E. 11th Ave., P.O. Box 3621, Portland, OR 97208; 503-230-INFO [4636]; 800-622-4520

Public Engagement P.O. Box 14428, Portland, OR 97293; 800-622-4519; *www.bpa.gov/comment*

Washington, D.C., Office Forrestal Bldg., Room 8G-061, 1000 Independence Ave. S.W., Washington, D.C. 20585; 202-586-5640

Crime Witness Program To report crimes to BPA property or personnel; 800-437-2744

TRANSMISSION SERVICES

Transmission Services Headquarters P.O. Box 491, Vancouver, WA 98666-0491; 503-230-3000

Ross Complex 5411 N.E. Highway 99, Vancouver, WA 98663; 503-230-3000"

Van Mall One Park Place 7600 NE 41st Street, Vancouver WA 98662, 503-230-3000

Covington District 28401 Covington Way S.E., Kent, WA 98042; 253-638-3700

Eugene District 86000 Hwy. 99 S., Eugene, OR 97405; 541-988-7401

Idaho Falls Regional Office 1350 Lindsay Blvd., Idaho Falls, ID 83402; 208-612-3100

Kalispell District 2520 U.S. Hwy. 2 E., Kalispell, MT 59901; 406-751-7802

Longview District 3750 Memorial Park Drive, Longview, WA 98632; 360-414-5600

Olympia Regional Office 5240 Trosper Road S.W., Olympia, WA 98512; 360-570-4305

Redmond District 3655 S.W. Highland Ave., Redmond, OR 97756; 541-516-3200

Salem District 2715 Tepper Lane N.E., Keizer, OR 97303; 503-304-5900

Snohomish District 914 Ave. D, Snohomish, WA 98290; 360-563-3600

Spokane District 2410 E. Hawthorne Road, Mead, WA 99021; 509-468-3002

The Dalles District 3920 Columbia View Drive E., The Dalles, OR 97058; 541-296-4694

Tri-Cities District 2211 N. Commercial Ave., Pasco, WA 99301; 509-544-4702

Wenatchee District 13294 Lincoln Park Road, East Wenatchee, WA 98802, 509-886-6000

POWER SERVICES

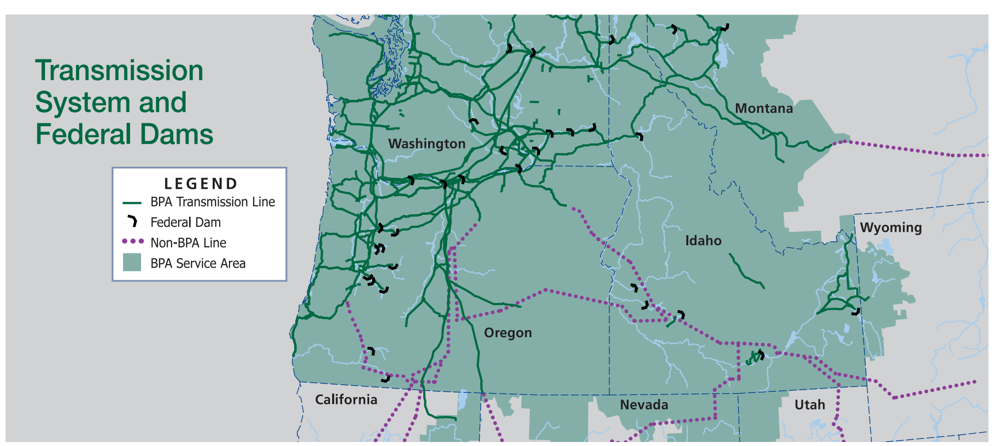
Boise Customer Service Center 950 W. Bannock St., Suite 805, Boise, ID 83702; 208-670-7406

Eastern Area Customer Service Center P.O. Box 789, Mead, WA 99021; 509-822-4591

Montana Customer Service Center P.O. Box 640, Ronan, MT 59864; 406-676-2669

Seattle Customer Service Center 915 Second Ave., Suite 3360, Seattle, WA 98174; 206-220-6770

Western Area Customer Service Center 905 N.E. 11th Ave., P.O. Box 3621, Portland, OR 97208; 503-230-5856



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-26-18

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

Exhibit 2-74:
Department Export Authorization EA-479-A (July 11, 2025)

United States

Department of Energy

Grid Deployment Office

Macquarie Energy LLC

GDO Docket No. EA-479-A

Order Authorizing Electricity Exports to Canada

Order No. EA-479-A

July 11, 2025

Macquarie Energy LLC
Order No. EA-479-A

Authorizing Electricity Exports to Canada

I. BACKGROUND

The Department of Energy (DOE or Department) regulates electricity exports from the United States to a foreign country in accordance with Federal Power Act (FPA) § 202(e) (16 U.S.C. § 824a(e)) and regulations thereunder (10 C.F.R. §§ 205.300 *et seq.*). This authority was transferred to DOE under §§ 301(b) and 402(f) of the DOE Organization Act (42 U.S.C. §§ 7151(b) and 7172(f)). On April 10, 2023, this authority was delegated to the DOE's Grid Deployment Office (GDO) by Redelegation Order No. S3-DEL-GD1-2023.

An entity that seeks to export electricity must obtain an order from DOE authorizing it to do so. Under FPA § 202(e), DOE "shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has discretion to condition the order as necessary or appropriate; the Department "may by its order grant such application in whole or in part, with such modifications and upon such terms and conditions as [DOE] may find necessary or appropriate, and may from time to time, after opportunity for hearing and for good cause shown, make such supplemental orders in the premises as it may find necessary or appropriate." *Id.*

A. APPLICATION TO RENEW EXPORT AUTHORIZATION

Macquarie Energy LLC (Macquarie Energy or Applicant) is a power marketer seeking renewal of its existing authorization to export electric energy to Canada, which was originally granted in Order No. EA-479 on November 21, 2019, for a five-year term. On August 30, 2024, Macquarie Energy filed an application with DOE (Application or App.) for renewal of their export authority. App. at 1.

According to its Application, Macquarie Energy LLC operates as a "marketer and broker of electric power at wholesale." *Id*. at 1. The Applicant represents that it is "a Delaware corporation with its office and principal place of business in Houston, Texas" and "an indirect, wholly-owned subsidiary of Macquarie Group Ltd., an Australian company listed on the Australian Stock Exchange." *Id*. Macquarie Energy states that "the Federal Energy Regulatory Commission [FERC] has authorized Macquarie Energy to engage in wholesale sales of electric energy, capacity, and ancillary services at market-based rates." *Id.*

Macquarie Energy represents that it "does not own or control any electric power generation or transmission facilities and does not have a franchised electric power service area." App. at 1. Macquarie Energy states that it "does not have its own 'system' on which its exports of energy could have a reliability or stability impact" and it "will purchase the energy to be exported from wholesale generators, electric utilities, power marketers, Independent System Operators, Regional Transmission Authorities, and federal power marketing agencies." *Id.* at 2. The Applicant further states that "such energy is surplus to the system of the generator and thus, exportation of said energy will not impair the adequacy of the electric power supply within the United States." *Id*. Additionally, Macquarie Energy asserts that it will comply with all applicable reliability criteria, standards, and guidelines. *See id*. at 3.

B. PROCEDURAL HISTORY

On August 30, 2024, Macquarie Energy filed an application with DOE requesting a renewal of their authorization to export electrical energy to Canada for an additional term of five (5) years. App. at 1. On October 18, 2024, DOE published notice of Macquarie Energy's Application in the Federal Register (89 Fed. Reg. 83867) and asked for any interested parties to submit comments on the Application by November 18, 2024.

C. PUBLIC COMMENTS

1. Public Citizen's Motion to Intervene and Protest

On November 18, 2024, Public Citizen, Inc. (Public Citizen) submitted a Motion to Intervene and Protest to the Application (Public Citizen Mot.). Public Citizen states it is "a national, not-for-profit, non-partisan organization that represents the public interest generally and, even more closely relevant to this proceeding interests of household consumers." Public Citizen Mot. at 2. Public Citizen asserts that Macquarie Energy misrepresented that it does not own generation or transmission facilities and does not have a franchised power service area, noting that Macquarie Energy's affiliates "hold controlling interests in two utilities with franchised electric service areas which include transmission facilities[,]" including Puget Sound Energy and Cleco Power. *Id.* at 1. In addition, Public Citizen claims that Macquarie owns or is seeking to acquire a number of power generation assets. *See id.*

Public Citizen also argues that Macquarie Energy did not disclose that it is a defendant in litigation accused of energy market manipulation and the subject of an investigation by FERC's Office of Enforcement for market manipulation during Winter Storm Uri. Public Citizen Mot. at 1. Public Citizen asserts that Macquarie's control of Multifuels Midstream Group "helped inform Macquarie's price-gouging trading operation in Texas[,]" referencing a news article noting "Macquarie earned $215 million in windfall profits" during the storm. *Id.* at 1-2. Public Citizen asserts that DOE should not approve Macquarie's request to export energy until the allegations of market manipulation have been resolved. *Id.* at 1.

2. Macquarie Energy's Answer

On November 27, 2024, Macquarie Energy filed a Motion for Leave to Answer and Answer of Macquarie Energy LLC to Protest of Public Citizen (Macquarie Ans.). Macquarie Energy asserts that Public Citizen did not request specific relief in its motion and did not address the applicable standard of review for electricity export authorization applications. Macquarie Ans. at 2.

Macquarie Energy further denies Public Citizen's allegations, maintaining that it does not own electric generation or transmission facilities and does not have a franchised power service area. Macquarie Ans. at 3. Macquarie Energy acknowledges that its affiliates own electric generation and transmission facilities and have franchised power service areas. *Id.* However, Macquarie Energy notes that none of these entities are seeking an electricity export authorization, and Macquarie Energy "is incapable of controlling any of the asserts owned and/or operated" by such affiliates. *Id.*

Further, Macquarie Energy asserts that Public Citizen's allegations regarding market manipulation by Multifuels Midstream Group, an affiliate of Macquarie Energy by virtue of common upstream ownership, are not probative of the supply and reliability considerations that inform the review of electricity export applications. Macquarie Ans. at 3. Macquarie Energy further asserts that Public Citizen "presented no information to demonstrate this alleged misconduct." *Id.* Macquarie Energy states it "does not have any control over Multifuels Midstream Group as a function of common ownership." *Id.*

3. Public Citizen's Answer

On December 2, 2024, Public Citizen filed a Motion to Answer and Answer (Public Citizen Ans.). Public Citizen asserts that DOE must either reject Macquarie Energy's export authorization application or set the matter for hearing pursuant to 16 U.S.C. § 824a(e). Public Citizen Ans. at 1. Public Citizen maintains that the Applicant concealed material facts within its export authorization application, including its affiliation with "Puget Sound Energy and Cleco Power, as well as a number of power generation facilities in the United States." Public Citizen Ans. at 3. Additionally, Public Citizen disputes Macquarie Energy's assertion that it is incapable of controlling any assets of its affiliates and claims that Macquarie Energy engaged in transactions with Puget Sound Energy and Cleco Power, "making the omissions of these facts from [the Application] a fatal error." *Id.*

Public Citizen further asserts that Macquarie Energy's status as a defendant accused of market manipulation threatens the sufficiency of electric supply and impedes the coordination of energy facilities in the public interest. Public Citizen Ans. at 3-4. Public Citizen claims that "Macquarie appears to have systemic compliance problems[,]" pointing to penalties recently assessed to Macquarie Energy's affiliates. *Id.* at 4.

4. Macquarie Energy's Second Answer

On December 13, 2024, Macquarie Energy filed a second Motion for Leave to Answer and Answer of Macquarie Energy LLC to Answer of Public Citizen (Macquarie 2nd Ans.). Macquarie Energy states that it provided all information as required by 10 C.F.R. §§ 205.302-303. Macquarie 2nd Ans. at 2. The Applicant asserts that Public Citizen continues to raise issues outside of the scope of DOE's filing requirements for an electricity export application. *Id.* Macquarie Energy further argues that Public Citizen's assertions of market misconduct are irrelevant and that applicable laws and regulations do not require Macquarie Energy to describe ongoing regulatory or legal proceedings or to disclose to DOE whether it is a subject of a non-public investigation when applying for an export authorization. *Id.* at 3.

5. Granting of Motion to Intervene and Motions to Answer

On December 11, 2024, DOE granted Public Citizen's motion to intervene in this proceeding pursuant to FERC Rule 214, cited in DOE's notice of the Application and providing that a movant becomes a party if no opposition is filed. *See* 18 C.F.R. § 385.214(c). Macquarie Energy did not assert any arguments against Public Citizen participating in this proceeding as an intervenor. To clarify the issues brought forth and assist in DOE's evaluation, DOE further grants Macquarie Energy's Motion for Leave to Answer, Public Citizen's Motion to Answer, and Macquarie Energy's second Motion for Leave to Answer. *See* 18 C.F.R. § 385.213(a)(2) (providing decisional authority discretion to permit answers to protests and answers); *see also* 10 C.F.R § 205.304 (providing supplemental information may be collected from applicant).

II. DISCUSSION AND ANALYSIS

DOE is statutorily obligated under FPA § 202(e) to grant requests for export authorization unless the Department finds that the proposed export would negatively impact either: (i) the sufficiency of electric supply, or (ii) the coordination of the electric grid. Regarding the first exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States …." 16 U.S.C. § 824a(e). DOE has interpreted this criterion to mean that sufficient generating capacity and electric energy must exist such that the export could be made without compromising the energy needs of the exporting region, including serving all load obligations in the region while maintaining appropriate reserve levels. *See, e.g.*, *BP Energy Co.*, Order No. EA-314, at 1-2 (Feb. 22, 2007), *renewed*, Order No. EA-314-A, at 2 (May 3, 2012), Order No. EA-314-B, at 2 (Feb. 28, 2017), *renewed,* Order No. EA-314-C, at 4 (Dec. 20, 2021).

Under the second exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would … impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has interpreted this criterion primarily as an issue of the operational reliability of the domestic electric transmission system. Accordingly, the export must not compromise transmission system security and reliability. *See, e.g.*, Order No. EA-314-C, at 4.

A. Macquarie Energy's Application Complies with Applicable DOE Requirements Regarding Disclosing Corporate Affiliates

DOE's regulations at 10 C.F.R. §§ 205.302–303 outline the contents and exhibits required for electricity export applications. Public Citizen's filings do not point to any DOE requirement to submit information related to an applicant's corporate affiliates. Notwithstanding, related to corporate affiliates, DOE's regulations require applicants to disclose the "exact legal name of all partners" (10 C.F.R. § 205.302(b)) and any corporate relationships or existing contracts, which relate "to the control or fixing of rates for the purchase, sale or transmission of electric energy" (10 C.F.R. § 205.303(e)).

According to the Application, Macquarie Energy is not a partnership, but an "indirect, wholly-owned subsidiary of Macquarie Group Ltd." that operates as a limited liability corporation under the laws of Delaware. *See* App. at 1 & Exhibit B. Additionally, Macquarie Energy's Application states that the information required to be reported under 10 C.F.R. § 205.303(e) does not apply in its case. *See id.* at Exhibit E. According to the Application, Macquarie Energy has been authorized by FERC to engage in wholesale sales of electric energy, capacity, and ancillary services at market-based rates. *Id.* at 1. Macquarie Energy provided a copy of its market-based rate tariff under which it engages in wholesale electric power sales. *Id.* at n.3 & Attachment 1.

DOE notes that to receive market-based rate authority from FERC, sellers must demonstrate to FERC a lack of horizontal and vertical market power, which includes providing a description of the seller's ownership structure and identifying its affiliates. *See* 18 C.F.R. § 35.37; *see also* §§ 35.39 (placing restrictions on affiliate sales of electric energy), 35.42(a)(2) (requiring market-based rate sellers to report changes in affiliations). Evidence of market-based rate authority from FERC supports the Applicant's representation that it does not have any corporate relationships or contracts relating to the control or fixing of rates as described in 10 C.F.R. § 205.303(e).

Accordingly, DOE determines that Macquarie's Application complies with the applicable DOE requirements regarding disclosing corporate affiliates.

B. Public Citizen Has Not Provided Sufficient Evidence of Impacts to the Factors Analyzed under the FPA § 202(e) Standard of Review

As stated above, FPA § 202(e) directs DOE to issue export authorizations unless DOE finds that the proposed exports would negatively impact either the sufficiency of electric supply or the coordination of the electric grid. Public Citizen claims that Macquarie Energy has been accused of market manipulation and that "[m]arket manipulation interrupts the sufficiency of electric supply, and impedes the coordination of energy facilities in the public interest[.]" Public Citizen Ans. at 3-4. However, Public Citizen's filings fail to establish how and to what extent these factors are impacted, presenting no additional evidence related to the applicable standard of review beyond its general assertion.

Further, according to Public Citizen's filings, the proceedings in which these market misconduct claims have been brought forth remain pending, and therefore the allegations have yet to be proven. DOE notes that such claims may be better suited for review and adjudication by the court in which they have been raised or by FERC in any investigation that has been initiated. Should these claims hold merit, the court or FERC would be equipped to provide any necessary remedies and oversight.

In sum, DOE determines that Public Citizen has not provided sufficient evidence to support that any alleged market manipulation would impact the sufficiency of electric supply or the coordination of the electric grid according to the standard of review under FPA § 202(e).

C. Macquarie Energy's Requested Authorization Will Not Impair the Sufficiency of Electric Supply in the United States

Sufficiency of supply, the first exception criterion, addresses whether regional electricity needs are met in the current market. DOE has analyzed this issue from both an economic and a reliability perspective. The economic perspective concerns the supply available to wholesale market participants. The reliability perspective focuses on preventing problems that could result from inadequate supplies. Taken together, DOE examines whether existing electric supply is available via market mechanisms, and whether potential reliability issues linked to supply problems are mitigated by reliability enforcement mechanisms.

From an economic perspective, DOE finds that the wholesale energy markets are sufficiently robust to make supplies available to exporters and other market participants serving United States regions along the Canadian and Mexican borders. Following enactment of the Energy Policy Act of 1992, Pub. L. No. 102-486, which encouraged the Federal Energy Regulatory Commission (FERC) to foster competition in the wholesale energy markets through open access to transmission facilities, energy markets developed across the United States to provide opportunities for a more efficient availability of supply. Subsequently, the Energy Policy Act of 2005, Pub. L. No. 109-58, reaffirmed the Government's commitment to competition in wholesale energy markets as national policy. FERC has continued to encourage the expansion of wholesale energy markets through its orders to remove barriers[1] and to ensure that these markets are functioning

[1] *See, e.g.*, *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

properly.[2] As a result, market participants have access to traditional bilateral contracts, as well as organized electricity markets run by regional transmission organizations (RTOs) or independent system operators (ISOs). FERC oversees these interstate wholesale electricity markets across most of the lower 48 states. Absent an indication in the record that the geographic markets relevant to this export authorization analysis are flawed and result in uneconomic exports that jeopardize regional supply, DOE finds that the proposed transmission for export does not impair the sufficiency of electric supply within the United States.

From a reliability perspective,[3] DOE focuses on the prevention of cascading outages and other problems that could result from inadequate resources.[4] Reliability oversight is addressed by the authority granted to FERC through the Energy Policy Act of 2005. That Act added section 215 to the FPA, which directed FERC to certify an electric reliability organization and develop procedures for establishing, approving, and enforcing mandatory electric reliability standards. 16 U.S.C. § 824o. FERC certified NERC in 2006 to develop and enforce reliability standards for the bulk-power system in the United States. *Order Certifying NERC as the Electric Reliability Organization and Ordering Compliance Filing*, FERC Docket No. RR06-1-000, 116 FERC ¶ 61,062 (July 20, 2006). FERC approves these standards, at which point they become mandatory and enforceable. NERC Reliability Standards address areas such as resource and demand balancing, critical infrastructure protection, communications, emergency preparedness and operations, facilities design, transmission operations, transmission planning, modelling, nuclear, personnel performance and training, protection and controls, voltage and reactive, interchange scheduling and coordination, and interconnection reliability operations and coordination.

NERC Reliability Standards are enforceable throughout the continental United States, most of Canada south of the 60th parallel, and the Mexican state of Baja California Norte. Through enforcement by FERC, NERC, and six Regional Entities overseen by NERC,[5] all bulk-power system owners, operators, and users are held responsible for complying with reliability standards. The reliability standards are structured so that many entities have overlapping responsibility for the electric grid, thereby resulting in several layers of reliability monitoring. Entities such as reliability coordinators and balancing authorities coordinate power generation and transmission

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[2] *See, e.g.*, *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *as amended*, 126 FERC ¶ 61,261, *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[3] A related reliability analysis follows in the next section of this Order.

[4] This focus should not be confused with resource adequacy planning and capacity requirements that have traditionally been the domain of state regulatory commissions, NERC-certified Regional Entities, and RTOs/ISOs.

[5] The six entities are the Midwest Reliability Organization, Northeast Power Coordinating Council, Reliability *First* Corporation, SERC Reliability Corporation, Texas Reliability Entity, and Western Electricity Coordinating Council.

among multiple utilities to serve demand within an integrated regional wholesale market. One of the principal functions of these entities is to schedule adequate generating and reserve capacity. This allows them to serve demand at the regional level and to ensure that there is sufficient power supply to maintain system reliability. Reliability Standard IRO-001-4 "establish[es] the responsibility of Reliability Coordinators to act or direct other entities to act."[6] Requirement R1 states that "[e]ach Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions."[7] Reliability oversight is designed through coordinated efforts amongst Reliability Coordinators to preserve the benefits of interconnected operations and ensure that operations in one area will not adversely impact other areas.[8] Reliability Standard IRO-014-3 R1 provides that "[e]ach Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability."[9]

DOE finds that NERC's FERC-approved comprehensive enforcement mechanism ensures that bulk-power system owners, operators, and users have a strong incentive both to maintain system resources and to prevent reliability problems that could result from movement of electric supplies through export. As a result of this reliability oversight, DOE finds that the sufficiency of supply is not impaired by Macquarie Energy's proposed export authorization.

DOE's sufficiency of supply findings are further supported by the fact that power marketers, such as Macquarie Energy, do not have an obligation to serve a franchised territory. Before the current role of power marketers emerged in the industry, the FPA § 202(e) inquiry into sufficiency of supply had a narrower focus and was designed for an applicant that was a vertically integrated utility[10] with an obligation to serve native load. Under that traditional scenario, the inquiry regarding sufficiency of supply logically sought to confirm that exports would be surplus to the needs of a vertically-integrated utility's native load obligations and reserve margins. As explained in DOE's notice of the first application by a power marketer for export authorization, the sufficiency of supply inquiry became unnecessary when applied to power marketers:

[6] Standard IRO-001-4 (Reliability Coordination – Responsibilities), at ¶ A.3.

[7] *Id.* ¶ B.R1.

[8] *See* Standard IRO-014-3 (Coordination Among Reliability Coordinators), at ¶ A.3.

[9] *Id.* ¶ B.R1.

[10] The Supreme Court of the United States has explained: "In 1935, when the FPA became law, most electricity was sold by vertically integrated utilities that had constructed their own power plants, transmission lines, and local delivery systems…[M]ost operated as separate, local monopolies subject to state or local regulation. Their sales were 'bundled,' meaning that consumers paid a single charge that included both the cost of the electric energy and the cost of its delivery. Competition among utilities was not prevalent." *New York v. FERC*, 535 US 1, 5 (2002).

> The Applicant also is required to demonstrate that it would have sufficient generating capacity to sustain the proposed export under the terms and conditions of its export agreement, while still complying with any established reserve criteria.
>
> Since marketers generally could not be seen as having any "native load" requirements, the latter criterion of maintaining sufficient reserve margins appears inappropriate and unnecessary in this instance.

59 Fed. Reg. 54900 (Nov. 2, 1994). Power marketers do not have franchised service areas and, consequently, do not have native load obligations like a traditional local distribution utility that could be impaired by exports.

In sum, market mechanisms and reliability oversight protect against the possibility that Macquarie Energy's exports would jeopardize domestic sufficiency of supply. Therefore, an export by Macquarie Energy would not trigger the first exception criterion of FPA § 202(e) regarding the sufficiency of electric supply within the United States.

D. Macquarie Energy's Requested Authorization Will Not Adversely Affect Either the Reliability or the Security of the United States Electric Transmission System

Reliability, the second exception criterion under FPA § 202(e), addresses operational reliability and security of the domestic electric transmission system. In evaluating the operational reliability impacts of export proposals, DOE has used a variety of methodologies and information, including established industry guidelines, operating procedures, and technical studies where available and appropriate. When determining these impacts, it is convenient to separate the export transaction into two parts: (i) moving the export from the source to a border system that owns the international transmission connection, and (ii) moving the export through that border system and across the border.

Moving Electricity to a Border System. Moving electricity for export to a border system necessarily involves the use of the bulk-power system. As noted in the preceding section, bulk-power system reliability concerns are addressed under the FPA by FERC and NERC and involve the enforcement of mandatory reliability standards. These standards ensure that all owners, operators, and users of the bulk-power system have an obligation to maintain system security and reliability. The standards are structured so that there are always entities with broader responsibilities than the applicant, such as reliability coordinators and balancing authorities, to keep a constant watch over the domestic transmission system.

To deliver the export from the source to a border system, the applicant must make the necessary commercial arrangements and obtain sufficient transmission capacity to wheel the exported energy to the border system. The applicant would be expected to follow FERC orders regarding open transmission access and to schedule delivery of the export with the appropriate RTO, ISO, and/or balancing authority (formerly the control area operator).

It is the responsibility of the RTO, ISO, and/or balancing authority to schedule the delivery of the export consistent with established and mandatory operational reliability criteria. During each step of the process of obtaining transmission service, the owners and/or operators of the transmission facilities will evaluate the impact on the system and schedule the movement of the export *only* if it would not violate established operating reliability standards. As a failsafe, the reliability coordinator in each region has the authority and responsibility to curtail, cancel, or deny scheduled flows to avoid shortages or to restore necessary energy and capacity reserves. Reliability Standard EOP-011-1 R2 provides that "[e]ach Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area."[11]

Specifically, the reliability coordinator has the authority to suspend exports if the electric energy would be needed to support the regional power grid. *See* Reliability Standard IRO-001-4 R1 ("Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions"), R2 ("Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements"), and R3 ("Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1").

DOE has determined that the existing industry procedures for obtaining transmission capacity on the domestic transmission system (described above) provide adequate assurance that any export will not cause an operational reliability problem. Therefore, Macquarie Energy's export authorization has been conditioned to ensure that the export will not cause operational issues on regional transmission systems to fall outside of established industry reliability criteria, or cause or exacerbate a transmission operating problem on the United States' electric power supply system (*see* Order below, Section VII, paragraphs C, D, and I).

Moving Electricity Through a Border System. The second part of DOE's reliability inquiry, addressing the transmission of the export through a border system and across the border, is a question of whether the border system is reliable and secure. To a large extent, this question is addressed by the jurisdiction of NERC. NERC and Regional Entities—including the Midwest Reliability Organization, the Northeast Power

[11] EOP-011-1 (Emergency Operations), at ¶ B.R2.

Coordinating Council, and the Western Electricity Coordinating Council—oversee the United States-Canadian border system and a significant part of the United States-Mexican border system. Those border systems are generally subject to the same reliability standards as domestic systems. *See, e.g.*, http://www.ieso.ca/sector-participants/system-reliability/reliability-standards-framework.

DOE also relies on the System Impact Studies submitted in conjunction with an application for a DOE-issued Presidential permit[12] to construct a new international transmission line. As DOE has previously reviewed System Impact Studies submitted with Presidential permit applications,[13] DOE does not need to perform additional impact assessments here, provided the maximum rate of transmission for all exports through a border system does not exceed the authorized limit of the system (*see* Order below, Section VII, paragraph (A)). In its Application, Macquarie Energy committed to complying with all reliability limits on border facilities. *See* App. at 3. The second part of the reliability inquiry is therefore satisfied by DOE regulatory oversight, in addition to NERC's reliability enforcement.

III. FINDINGS AND DECISION

A. Macquarie Energy Meets the Statutory Requirements to Export Electric Energy to Canada

As explained above, DOE has assessed the impact that the proposed export would have on the reliability of the United States electric power supply system. DOE has determined that the export of electric energy to Canada by Macquarie Energy, as ordered below, would not impair the sufficiency of electric power supply within the United States and would not impede or tend to impede the coordination in the public interest of facilities within the meaning of FPA § 202(e).

B. Macquarie Energy Qualifies for a NEPA Categorical Exclusion for Exports of Electric Energy

Macquarie Energy's Application qualifies for DOE's categorical exclusion for exports of electric energy under the National Environmental Policy Act of 1969, as amended (NEPA), 42 U.S.C. § 4321 *et seq*. DOE's regulations set forth this categorical exclusion, codified as "B4.2," as follows:

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[12] DOE issues Presidential permits pursuant to Executive Order 10,485, as amended by Executive Order 12,038. *See* 10 C.F.R. §§ 205.320-205.329.

[13] *See, e.g.*, *AEP Tex. Cent. Co.*, Order No. PP-317, at 2-3 (Jan. 22, 2007); *Mont. Alta. Tie Ltd.*, Order No. PP-305, at 2-4 (Nov. 17, 2008).

> Export of electric energy as provided by Section 202(e) of the Federal Power Act over existing transmission lines or using transmission system changes that are themselves categorically excluded.

10 C.F.R. Part 1021, App. B to Subpart D, § B4.2.

DOE has determined that actions in this category do not individually or cumulatively have a significant effect on the human environment and that, therefore, neither an environmental assessment nor an environmental impact statement normally is required. 10 C.F.R. § 1021.410(a). Further, in 2011, DOE formally reviewed its NEPA regulations and categorical exclusions and determined that it was appropriate to retain the B4.2 categorical exclusion. *See* National Environmental Policy Act Implementing Procedures, 76 Fed. Reg. 214, 217 (Jan. 3, 2011); National Environmental Policy Act Implementing Procedures, 76 Fed. Reg. 9981, 9982 (Feb. 23, 2011).

To invoke this categorical exclusion, DOE must determine that, in relevant part, "[t]here are no extraordinary circumstances related to the proposal that may affect the significance of the environmental effects of the proposal," and that "[t]he proposal has not been segmented to meet the definition of a categorical exclusion." 10 C.F.R. § 1021.410(b)(2), (3). "Extraordinary circumstances" include "unique situations" such as "scientific controversy about the environmental effects of the proposal." *Id.* § 1021.410(b)(2). DOE finds that Macquarie Energy's Application does not present such a circumstance, nor has it been segmented for purposes of this exclusion. Macquarie Energy seeks to deliver electricity over existing international electric transmission facilities, which fits squarely within the B4.2 categorical exclusion. For these reasons, DOE will not require more detailed NEPA review in connection with this Application. *See*, *e.g.*, *id.* §§ 1021.400(a)(1), 1021.410; 40 C.F.R. § 1501.4(a).

C. Conclusion

DOE grants Macquarie Energy's requested authorization for a five (5) year term. Macquarie Energy is authorized to export electricity to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties, subject to the limitations and conditions described in this Order.

IV. DATA COLLECTION AND REPORTING REQUIREMENTS

The responsibility for the data collection and reporting under orders authorizing electricity exports to a foreign country currently rests with the U.S. Energy Information Administration (EIA) within DOE. The Applicant is instructed to follow EIA instructions in completing this data exchange. Questions regarding the data collection and reporting requirements can be directed to EIA by email at EIA4USA@eia.gov or by phone at 1-855-342-4872.

Additionally, any change to the tariff of an entity with an export authorization must be provided to DOE's Grid Deployment Office via email at *electricity.exports@hq.doe.gov*. 10 C.F.R. § 205.308(b).

V. COMPLIANCE

Obtaining a valid order from DOE authorizing the export of electricity under FPA § 202(e) is a necessary condition before engaging in the export. Failure to obtain such an order or continuing to export after the expiration of such an order may result in a denial of authorization to export in the future and subject the exporter to sanctions and penalties under the FPA. DOE expects transmitting utilities owning border facilities and entities charged with the operational control of those border facilities, such as ISOs, RTOs, or balancing authorities, to verify that companies seeking to schedule an electricity export have the requisite authority from DOE to export such energy.

DOE expects Macquarie Energy to abide by the terms and conditions established for its authority to export electric energy to Canada, as set forth below. DOE intends to monitor Macquarie Energy's compliance with these terms and conditions, including the requirement in paragraph G of this Order that Macquarie Energy create and preserve full and complete records and file reports with EIA as discussed above.

A violation of any of these terms and conditions, including the failure to submit timely and accurate reports, may result in the loss of authority to export electricity and subject Macquarie Energy to any applicable sanctions and penalties under the FPA.

VI. OPEN ACCESS POLICY

An export authorization issued under FPA § 202(e) does not impose a requirement on transmitting utilities to provide service. However, DOE expects transmitting utilities that own border facilities to provide open access transmission service across the border in accordance with the principles of comparable open access and non-discrimination contained in the FPA and articulated in FERC Order No. 888 (Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, FERC Statutes and Regulations ¶ 31,036 (1996)), as amended. The actual rates, terms, and conditions of transmission service should be consistent with the non-discrimination principles of the FPA and the transmitting utility's Open-Access Transmission Tariff on file with FERC.

All recipients of export authorizations, including owners of border facilities for which Presidential permits have been issued, are required by their export authorization to conduct operations in accordance with the applicable principles of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended. Cross-border electric trade ought to be subject to the same principles of comparable open access and non-discrimination that apply to transmission in interstate commerce. *See Enron Power Mktg., Inc. v. El Paso Elec. Co.*, 77 FERC ¶ 61,013 (1996), *reh'g denied*, 83 FERC ¶ 61,213 (1998). Thus, DOE expects owners of border facilities to comply with the same principles of comparable open access and non-discrimination that apply to the domestic, interstate transmission of electricity.

VII. ORDER

Accordingly, pursuant to FPA § 202(e) and the Rules and Regulations issued thereunder (10 C.F.R. §§ 205.300-309), it is hereby ordered that Macquarie Energy is authorized to export electric energy to Canada under the following terms and conditions:

(A) The electric energy exported by Macquarie Energy pursuant to this Order may be delivered to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties in accordance with the export limits authorized by DOE.

(1) The following international transmission facilities located at the United States border with Canada are currently authorized by Presidential permit and available for open access transmission:[14, 15]

Owner	Location	Voltage	Permit No.[16]
Bangor Hydro-Electric Company	Baileyville, ME	345 kV	PP-89
Basin Electric Power Cooperative	Tioga, ND	230 kV	PP-64
Bonneville Power Administration (BPA)	Blaine, WA	2x 500 kV	PP-10
	Nelway, WA	230 kV	PP-36
	Nelway, WA	230 kV	PP-46
CHPE, LLC	Champlain, NY	±230 kV DC	PP-481
Eastern Maine Electric Cooperative	Calais, ME	69 kV	PP-32
International Transmission	Detroit, MI	230 kV	PP-230

[14] This Order authorizes the export of electricity over any "authorized international transmission facility," which is intended to include both large transmission lines and smaller distribution lines that have received a Presidential permit. However, the list in subparagraph (A)(1) of current facilities only includes transmission lines.

[15] The Applicant submitted a list identifying currently authorized transmission facilities (Exhibit C of the Application). However, as information about some of those facilities may have changed since the Application was submitted, the table of transmission facilities in this Order may differ from the Applicant's submission to reflect those changes.

[16] These Presidential permit numbers refer to the generic DOE permit number and are intended to include any subsequent amendments to the permit authorizing the facility.

Company	Marysville, MI	230 kV	PP-230
	St. Claire, MI	230 kV	PP-230
	St. Claire, MI	345 kV	PP-230
ITC Lake Erie Connector	Erie County, PA	320 kV	PP-412[17]
Long Sault, Inc.	Massena, NY	2x 115 kV	PP-24
Maine Electric Power Company	Houlton, ME	345 kV	PP-43
Minnesota Power, Inc.	International Falls, MN	115 kV	PP-78
Minnesota Power, Inc.	Roseau County, MN	500 kV	PP-398
Minnkota Power Cooperative	Roseau County, MN	230 kV	PP-61
Montana Alberta Tie Ltd.	Cut Bank, MT	230 kV	PP-399
NECEC Transmission LLC	Beattie Twp, ME	±320 kV	PP-438[18]
New York Power Authority	Massena, NY	765 kV	PP-56
	Massena, NY	2x 230 kV	PP-25
	Niagara Falls, NY	2x 345 kV	PP-74
	Devils Hole, NY	230 kV	PP-30
Niagara Mohawk Power Corp.	Devils Hole, NY	230 kV	PP-190
Northern States Power Company	Red River, ND	230 kV	PP-45
	Roseau County, MN	500 kV	PP-63
	Rugby, ND	230 kV	PP-231
Sea Breeze Olympic Converter LP	Port Angeles, WA	±450 kV DC	PP-299[19]
TDI New England	Alburgh, VT	±320 kV DC	PP-400[20]

[17] These transmission facilities have been authorized but not yet constructed or placed into operation.

[18] These transmission facilities have been authorized but not yet constructed or placed into operation.

[19] These transmission facilities have been authorized but not yet constructed or placed into operation.

[20] These transmission facilities have been authorized but not yet constructed or placed into operation.

Vermont Electric Power Co.	Derby Line, VT	120 kV	PP-66
Vermont Electric Transmission Co.	Norton, VT	±450 kV DC	PP-76
Vermont Transco LLC	Highgate, VT	120 kV	PP-82
Versant Power	Easton, ME	7.2 kV	PP-499
	Fort Fairfield, ME	69 kV	PP-497
	Madawaska, ME	138 kV	PP-498
	Baileyville, ME	345 kV	PP-500

(2) The following are the authorized export limits for the international transmission lines listed above in subparagraph (A)(1):

(a) Exports by Macquarie Energy made pursuant to this Order shall not cause the total exports on facilities authorized by Presidential Permit PP-64 (issued to Basin Electric Power Coop.) to exceed an instantaneous transmission rate of 150 megawatts (MW). The gross amount of energy that Macquarie Energy may export over the PP-64 facilities shall not exceed 900,000 megawatt-hours (MWH) during any consecutive 12-month period.

(b) Exports by Macquarie Energy made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-32 (issued to Eastern Maine Electric Coop.) to exceed an instantaneous transmission rate of 15 MW. The gross amount of energy that Macquarie Energy may export over the PP-32 facilities shall not exceed 7,500 MWH annually.

(c) Exports by Macquarie Energy made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-481-2 (issued to CHPE, LLC) to exceed an instantaneous transmission rate of 1,250 MW.

(d) Exports by Macquarie Energy made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-230 (issued to International Transmission Company) to exceed a coincident, instantaneous transmission rate of 2.2 billion volt-amperes (2,200 MVA).

(e) Exports by Macquarie Energy made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-412 (issued to ITC Lake Erie Connector) to exceed an instantaneous transmission rate of 1,000 MW.

(f) Exports by Macquarie Energy made pursuant to this Order shall not cause the scheduled rate of transmission over a combination of facilities authorized by Presidential Permits PP-43 (issued to Versant) and PP-89-2 (issued to Bangor Hydro-Electric) to exceed 550 MW.

(g) Exports by Macquarie Energy made pursuant to this Order shall not cause the total exports on the combination of facilities authorized by Presidential Permits Presidential Permits PP-497 and PP-498 (issued to Versant Power) to exceed a coincident, instantaneous transmission rate of 97.8 MW.

(h) Exports by Macquarie Energy made pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-78-1 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 100 MW. Exports by Macquarie Energy may cause total exports on the PP-78-1 facilities to exceed 100 MW only when total exports between the Mid-Continent Area Power Pool (MAPP) and Manitoba Hydro are below maximum transfer limits and/or whenever operating conditions within the MAPP system permit exports on the PP-78-1 facilities above the 100-MW level without violating established MAPP reliability criteria. However, under no circumstances shall exports by Macquarie Energy cause the total exports on the PP-78-1 facilities to exceed 150 MW.

(i) Exports made by Macquarie Energy pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-398 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 750 MW.

(j) Exports by Macquarie Energy made pursuant to this Order shall not cause total exports on a combination of the international transmission lines authorized by Presidential Permits PP-45 and PP-63 (issued to Northern States Power Company), PP-61 (issued to Minnkota Power), and PP-231 (issued to Northern States Power Company, d/b/a Excel Energy Inc.(Xcel)), to exceed an instantaneous transmission rate of 700 MW on a firm basis and 1,050 MW on a non-firm basis.

(k) Exports by Macquarie Energy made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-66 (issued to Vermont Electric Power Co.) to exceed an instantaneous transmission rate of 50 MW. The gross amount of energy that Macquarie Energy may export over the PP-66 facilities shall not exceed 50,000 MWH annually.

(l) Exports by Macquarie Energy made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit

PP-56 (issued to NYPA) to exceed an instantaneous transmission rate of 1,000 MW.

(m) Exports by Macquarie Energy made pursuant to this Order shall not cause: (a) the total exports on the facilities authorized by Presidential Permits PP-25, PP-30, PP-74 (issued to NYPA), and PP-190 (issued to Niagara Mohawk Power Corp.) to exceed a combined instantaneous transmission rate of 1,650 MW; and (b) the total exports on the 115-kV facilities authorized by Presidential Permit PP-24 (issued to Long Sault, Inc.) to exceed an instantaneous transmission rate of 100 MW. In addition, the gross amount of energy that Macquarie Energy may export over the PP-24 facilities shall not exceed 300,000 MWH annually.

(n) Exports by Macquarie Energy made pursuant to this Order shall not cause total exports on the two 500-kV lines authorized by Presidential Permit PP-10, the 230-kV line authorized by Presidential Permit PP-36, and the 230-kV line authorized by Presidential Permit PP-46 (issued to BPA) to exceed the following limits:

Condition	PP-36 & PP-46 Limit	PP-10 Limit	Total Export Limit
All lines in service	400 MW	1500 MW	1900 MW
1-500 kV line out	400 MW	300 MW	700 MW
2-500 kV lines out	400 MW	0 MW	400 MW
1-230 kV line out	400 MW	1500 MW	1900 MW
2-230 kV line out	0 MW	1500 MW	1500 MW

(o) Exports by Macquarie Energy made pursuant to this Order shall not cause a violation of the following conditions as they apply to exports over the facilities authorized by Presidential Permit PP-76-1, as amended (issued to the Vermont Electric Transmission Company):

NEPOOL

Exports Through	Load Condition	Export Limit
Comerford converter	Summer, Heavy	650 MW
Comerford converter	Winter, Heavy	660 MW
Comerford converter	Summer, Light	690 MW
Comerford converter	Winter, Light	690 MW
Comerford & Sandy Pond converters	All	2,000 MW

(p) Exports by Macquarie Energy made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-399 (issued to Montana Alberta Tie Ltd.) shall not exceed an instantaneous transmission rate of 300 MW.

(q) Exports by Macquarie Energy made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-438 (issued to NECEC Transmission LLC) shall not exceed an instantaneous transmission rate of 1,200 MW.

(r) Exports by Macquarie Energy made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-299 (issued to Sea Breeze Olympic Converter LP) shall not exceed an instantaneous transmission rate of 550 MW.

(s) Exports by Macquarie Energy made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-400 (issued to TDI-New England) to exceed an instantaneous transmission rate of 1,000 MW.

(t) Exports by Macquarie Energy made pursuant to this Order shall neither cause the total exports on the facilities authorized by Presidential Permit PP-82-6 (issued to Vermont Transco LLC) to exceed an instantaneous transmission rate of 250 MW.

(B) Changes by DOE to the export limits in other orders shall result in a concomitant change to the export limits contained in subparagraph (A)(2) of this Order. Changes to the export limits contained in subparagraphs (A)(2)(l), (m), and (n) will be made by DOE after submission of appropriate information demonstrating a change in the transmission transfer capability between the electric systems in New York State and Ontario and New York State and Quebec, and between BPA and BC Hydro or BPA and West Kootenay Power. Notice of these changes will be provided to Macquarie Energy.

(C) Macquarie Energy shall obtain any and all other Federal and state regulatory approvals required to execute any power exports to Canada. The scheduling and delivery of electricity exports to Canada shall comply with all reliability criteria, standards, and guidelines of NERC, reliability coordinators, Regional Entities, RTOs, ISOs or balancing authorities, or their successors, as appropriate, on such terms as expressed therein, and as such criteria, standards, and guidelines may be amended from time to time.

(D) Exports made pursuant to this authorization shall be conducted in accordance with the applicable provisions of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended.

(E) The authorization herein granted may be modified from time to time or terminated by further order of DOE. In no event shall such authorization to export over a particular transmission facility identified in subparagraphs (A)(1) and (2) extend beyond the date of termination of the Presidential permit or treaty authorizing such facility.

(F) This authorization shall be without prejudice to the authority of any state or state regulatory commission for the exercise of any lawful authority vested in such state or state regulatory commission.

(G) Macquarie Energy shall make and preserve full and complete records with respect to the electric energy transactions between the United States and Canada. Macquarie Energy shall collect and submit the data to EIA as required by and in accordance with the procedures of Form EIA-111, "Quarterly Electricity Imports and Exports Report," and all successor forms.

(H) In accordance with 10 C.F.R. § 205.305, this export authorization is not transferable or assignable, except in the event of involuntary transfer by operation of law. Provided written notice of the involuntary transfer is given to DOE within 30 days, this authorization shall remain in effect temporarily. The authorization shall terminate unless an application for a new export authorization has been received by DOE within 60 days of the involuntary transfer. Upon receipt by DOE of such an application, this existing authorization shall continue in effect pending a decision on the new application. In the event of a proposed voluntary transfer of this authority to export electricity, the transferee and the transferor shall file a joint application for a new export authorization, together with a statement of the reasons for the transfer.

(I) Nothing in this Order is intended to prevent the transmission system operator from being able to reduce or suspend the exports authorized herein, as necessary and appropriate, whenever a continuation of those exports would cause or exacerbate a transmission operating problem or would negatively impact the security or reliability of the transmission system.

(J) Macquarie Energy has a continuing obligation to give DOE written notification as soon as practicable of any prospective or actual changes of a substantive nature in the circumstances upon which this Order was based, including but not limited to changes in authorized entity contact information or NERC compliance registry status.

(K) This authorization shall be effective as of July 11, 2025 and shall remain in effect for a period of five (5) years from that date. Application for renewal of this authorization may be filed within six (6) months prior to its expiration. Failure to provide DOE with at least one hundred twenty (120) days to process a renewal application and provide adequate opportunity for public comment may result in a gap in Macquarie Energy's authority to export electricity.

Issued in Washington, DC on July 11, 2025.

Chris Wright

Chris Wright
Secretary of Energy
U.S. Department of Energy

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-26-18

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

Exhibit 2-75:
Bonneville Resource Plan (compiled 2022 & 2024)

BONNEVILLE POWER ADMINISTRATION

2022 Resource Program

Contents

Section 1: Introduction

This report begins with a general overview, noting the purpose of the Bonneville Power Administrations' Resource Program, highlighting changes from previous assumptions and methodology, and summarizing key findings of the analyses. Following the overview is a more in-depth look at each component of the Resource Program, including the assumptions, methodologies and study results, along with a brief section on BPA's next steps culminating from the conclusions.

1.1 Overview

BPA launched its Resource Program shortly after passage of the Northwest Power Act in 1980 to assess the agency's need for power and reserves and to develop an acquisition strategy to meet those needs. The Resource Program study provides analysis and insight into long-term, least-cost power resource acquisition strategies. This study examines uncertainty in loads, water supply, resource availability and electricity market prices to develop a least-cost portfolio of resources that meet Bonneville's obligations.

The 2022 Resource Program covers the fiscal years 2024 – 2033 and includes updates made to the optimization process and refreshes inputs. This study also includes a high policy scenario that will help BPA understand how the resource solution results may be impacted by changes in key assumptions such as loads, candidate resource costs and market prices. The results yield a vision of the agency's needs and low-cost resource strategies across a range of future market conditions and policy environments.

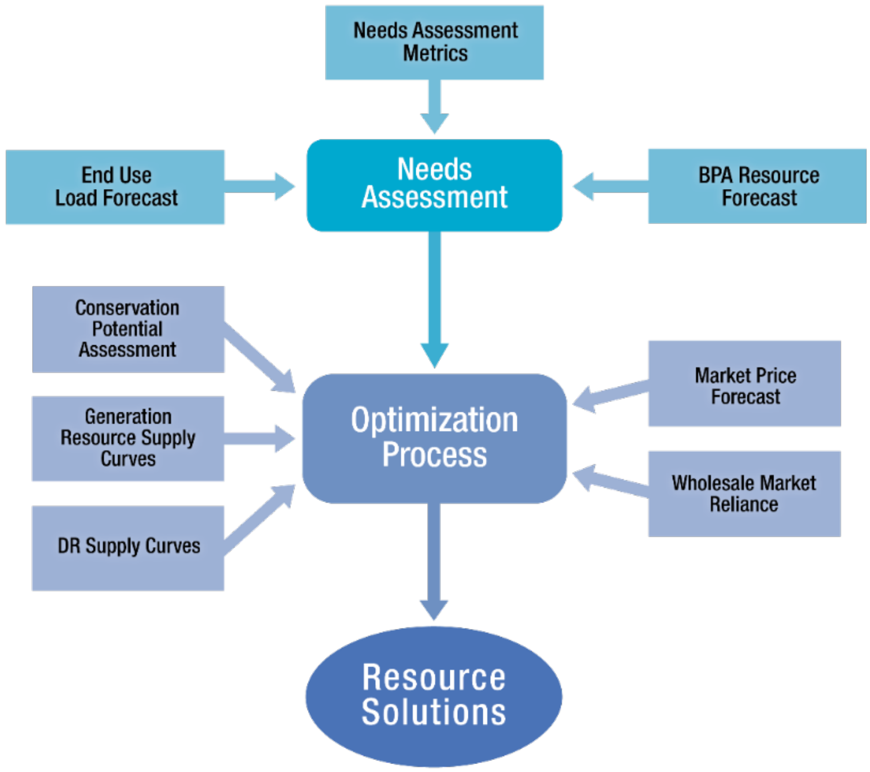
BPA's 2018-2023 Strategic Plan describes the actions it will take to remain a competitive supplier of low-cost power to its regional firm power customers. To support these strategic goals, the 2022 Resource Program details a comprehensive planning analysis that seeks to align BPA's resource acquisitions, including energy efficiency and demand response initiatives, with its long-term power supply needs.

The Resource Program is neither a decision document nor a process required by any external entity. Rather, it is a voluntary body of work, undertaken to inform acquisition strategies and provide valuable insight into how BPA can meet its obligations and strategic objectives at the least cost.

1.2 Methodology

The Resource Program begins with a forecast of BPA's obligations to supply firm power and the existing resources available to meet that demand, and then, determines any need for incremental energy or capacity in the Needs Assessment. The Resource Program next identifies and evaluates potential solutions to meeting those needs, including energy efficiency, demand response, candidate generating resources and power purchases. Finally, the Resource Program outlines potential strategies for meeting BPA's needs. Figure 1 provides a high-level diagram of the Resource Program process.

Figure 1: Resource Program Process



To assess the costs and benefits of resource solutions, BPA uses Aurora to create an electricity price forecast. Aurora is a computer software tool that can produce energy market price forecasts, value and uncertainty analyses, and automated system optimization. The energy market price forecast incorporates a natural gas price forecast, a renewables build forecast and assumptions around many other important factors, including regional generating resource retirements, negative price bidding activity and load forecasts for surrounding regions.

BPA also uses Aurora to perform a long-term capacity expansion and portfolio optimization analysis that assessed candidate resources' performances against 400 sets of potential future market conditions. The result of the optimization process is a set of 40 different portfolios that all meet Bonneville's needs at varying budget levels.

1.3 Conclusions

The below summarizes the main conclusions of the 2022 Resource Program:

- BPA has its greatest heavy load hour energy needs in October where large deficits are observed under low water conditions.

- By using a shorter historical period of streamflow record that represents the impacts of climate change on hydro generation, BPA expects more winter generation and less summer generation when compared to the use of a longer period of historical streamflows.

- BPA has surplus capacity in the winter and the summer, similar to the prior Resource Program.

- The expected market price for energy at the Mid-Columbia trading hub has increased over the market price forecast in the prior Resource Program.

- Similar to previous Resource Program findings, the least-cost mix of resources that will meet BPA's expected energy needs consists of conservation and energy purchased from the market. In addition, demand response was also included in the least-cost mix of resources for this Resource Program.

The following sections provide a more detailed look at the 2022 Resource Program. Additional files supporting the data sets shared in this report can be found at BPA's Resource Planning webpage.

Section 2: Needs Assessment

2.1 Overview

The Needs Assessment measures the federal system's[1] expected generating resource capabilities to meet projected load obligations under a range of conditions and timeframes for a 10-year study period, spanning fiscal years 2024-2033. The Needs Assessment studies occurred concurrently with a process to modernize the hydropower forecasts in the Bonneville Power Administration's long-term studies, as well as during a transition to using the 2020 modified streamflow data. BPA ultimately decided[2] to adopt the most recent 30 years of streamflow history, 1989-2018, in long-term forecasts rather than the historic 90-year record. BPA made this change in order to more realistically incorporate the impacts of climate change on federal system hydro generation.

As a result, the Needs Assessment reflects two streamflow sets: 1) the 2010 modified flows, which provide an 80-year period of record, hereafter "80-year study," and 2) the 2020 modified flows from which only 1989-2018 are used in the modeling, hereafter "30-year study." The 80-year study is included to help illustrate the change in energy and capacity positions due to climate impacts. However, the Resource Program analysis only carries the 30-year data forward into the optimization step of the process.

2.2 Methodology

The Needs Assessment incorporates hourly forecasts of federal system load obligations and resource capabilities.

Load obligations: BPA's Agency Load Forecasting system (ALF) produces load forecasts. ALF includes power sales contract obligations to public and federal agency customers and to the U.S. Bureau of Reclamation, as well as other contract obligations. ALF automatically includes projections of programmatic conservation savings expected to continue at levels established under current conservation programs. The Needs Assessment contains an ALF-produced frozen efficiency load forecast, which implements a combination of statistically adjusted end-use and econometric approaches. This means that historic energy efficiency achievement savings are projected forward in the load forecast, but the incremental conservation needed to meet the Northwest Power and Conservation Council's 2021 Northwest Power Plan targets are omitted from the load forecast.[3] ALF forecasting methodologies incorporate the most recent 15 years of regional temperatures, allowing the forecasts to incorporate the most recent climate trends. Also, the load forecast beyond the current Regional Dialogue contracts (post 2028) assumes no material contract election or rate structure differences from Regional Dialogue. ALF forecasts do not project additional temperature changes in the planning period.

Resources: BPA forecasts the resource capability using two computer models: 1) HYDSIM (Hydro System Simulator) for monthly and annual energy; and 2) Riverware for hourly energy and capacity. The models assess the resource capability to meet loads under expected load conditions and extreme temperature events over a range of possible water conditions and while meeting non-power requirements. The 80-

[1] Details on the federal system's generating capacity can be found in BPA's 2022 White Book.
[2] https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/climate-change-update-to-the-long-term-hydro-generation-forecast-letter.pdf [Accessed: 29 Aug 2022]
[3] The incremental conservation needed to meet the 2021 Northwest Power Plan targets and used to mitigate the deficits identified in this Needs Assessment will be discussed in section 4.4 – Portfolio Optimization Results.

year HYDSIM study used in the Needs Assessment is consistent with BPA's BP-22 Rate Case Final Proposal with updated flexible spill operations. To incorporate the federal system contract purchases and non-hydro generation in the study, the Riverware model operates to an hourly Federal Residual Hydro Load. The Federal Residual Hydro Load is the hourly federal load obligations minus the hourly contract purchases and non-hydro generation.

This assessment does not model any internal or regional transmission[4] constraints that may limit the ability to deliver the modeled system generation to load.

2.3 Studies & Metrics

As mentioned in the overview, the Needs Assessment focuses on two studies developed for FY 2024 through FY 2033: 80-year and 30-year. Depending on the study, up to four metrics, including annual energy and different capacity studies, were used to determine the ability of the federal system's generating capability to meet obligations.

- 80-year: This study uses data that is consistent with the federal system analysis load forecast in the BP-22 Rate Case Final Proposal, with the exception of including a frozen efficiency forecast. The 80-year study uses the 2010 modified streamflow data set, 1929-2008, and uses the 1937 water year as the critical, or firm, water condition.
- 30-year: This study uses data that is consistent with the federal system analysis load forecast in the BP-22 Rate Case Final Proposal, with the exception of including a frozen efficiency forecast. The 30-year study uses streamflow data from the most recent 30 years, 1989-2018, of the 2020 modified streamflow records from 1929-2018, or 90 water years.

The Needs Assessment used the following four metrics:

1. Annual Energy: This metric focuses on federal system annual average energy surplus/deficits under 1937-critical, or firm, water conditions. Only the 80-year study was used for this metric as it contains the 1937 water year and was consistent with the prior definition of firm annual energy at the time studies were produced. Future needs assements will instead use the "P10-by-month" definition of firm, which was recently adopted (see footnote 2 above).
2. Monthly P10 Heavy Load Hour Energy: This metric evaluates the lowest 10th percentile-by-month, or P10, of federal system surplus/deficit over heavy load hours. HLH refers to hour ending 07 to 22, totaling 16 hours each day, Monday through Friday; the other eight hours each day, Saturday and Sunday, and North American Electric Reliability Corporation holidays are light load hours. Each month is analyzed independently.
3. Monthly P10 Super-Peak Energy: This metric evaluates the P10 of federal system surplus/deficits over the six peak load hours per weekday by month. Each month is analyzed independently.
4. 18-Hour Capacity: This metric analyzes the federal system's ability to meet the six peak load hours per day over a three-day extreme weather event. Depending on the weather event, load obligations are adjusted for additional heating or cooling loads, and median water conditions are assumed for hydro generation. Additionally, load obligations assume that Canada requests maximum Canadian Entitlement energy deliveries available under terms of the Columbia River Treaty. Generating resources assume that wind generation is zero. Similarly, generation forecasts for the summer analysis— month of August—includes a 10% reduction in the Columbia Generating Station's generating capability to account for heat impacts on the CGS's cooling system. The Needs Assesment uses 80 water years to analyze the distribution of outcomes under different streamflow conditions.

[4] For additional detail on transmission, see the Transmission supplement section of BPA's 2022 Resource Program.

2.4 Results

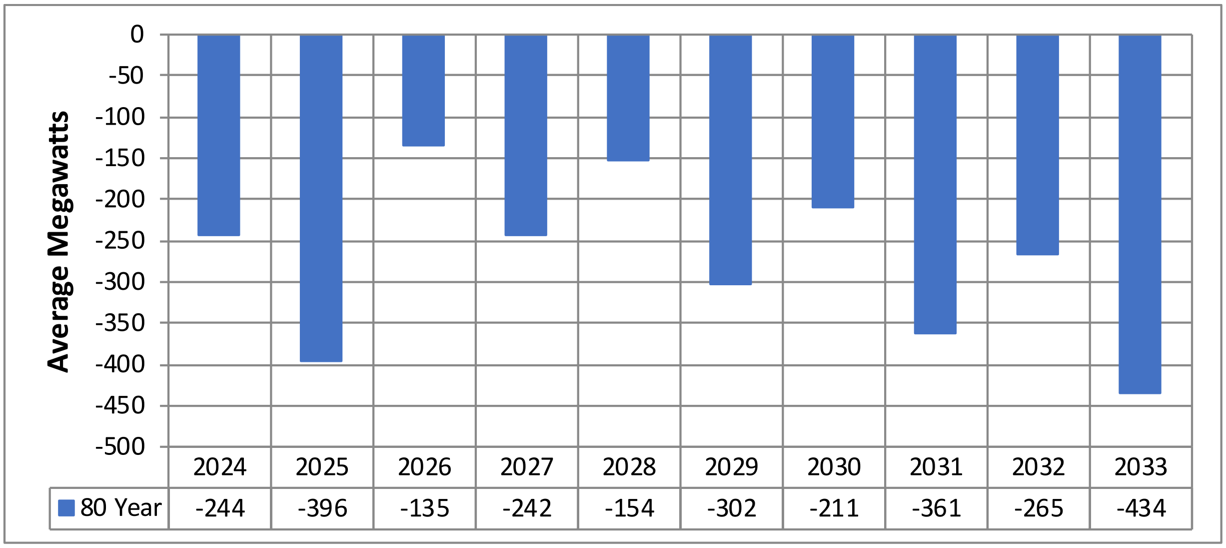
The Needs Assessment results show that the federal system has a wide range of potential deficits during the 10-year FY 2024-2033 period under the Annual Energy metric; see Figure 2. The Monthly P10 Heavy Load Hour metric shows larger deficits in October, January and the second half of April throughout the study period. The 30-year study shows less deficits in winter and more in August-October, consistent with trends of wetter, warmer winters and earlier streamflow recessions. Monthly P10 Super-Peak Energy metrics show deficits in the second half of April when low streamflows combine with significant increases in spill and restricted operating pools in the eight dams of the lower Columbia and Snake rivers; otherwise, the Super-Peak metric is surplus, and this result is consistent over the study period. Combined, the P10 HLH and Super-Peak metrics show that the system is generally able to serve the subset of six peak-load hours throughout the year under the low streamflow conditions, but the system is constrained for the full heavy load block in several months.

Lastly, the federal system is capacity surplus under the 18-Hour Capacity metric in both winter months (January) and summer months (August) when simulating increased loads due to extreme weather events. Previously, a single median water year was used to calculate this metric. Now, the full distribution of outcomes by water year is available. The distributions show that under the vast majority of water conditions, the system is able to serve the six peak-load hours each day during extreme weather over three consecutive days.

Annual Energy: The Annual Energy metric analyzes the ability of the federal system to meet energy loads on an annual basis.

> 80-year: Figure 2 shows a deficit of 244 average megawatts in FY 2024. The deficit grows to 396 aMW by FY 2025, recovers to 135 aMW in FY 2026, and then grows again to a deficit of 434 aMW by FY 2033. Hydro resources reflect the 2020 Columbia Rivers System Operations Environmental Impact Statement Preferred Alternative for the largest 14 federal dams. The difference between even and odd years is attributed to the Columbia Generating Station maintenance/refueling outage schedule. The decrease in deficit between FY 2025 to FY 2026 is due to the expiration of forward secondary surplus marketing activity that reduces obligations.

Figure 2: Annual Energy Surplus/Deficits – FY 2024 to FY 2033



Monthly P10 Heavy Load Hour Energy: Figure 3 presents the Monthly P10 HLH Energy metric for the 10-year study, and Figure 4 presents a selection of FY 2025-2026 to show the values in more detail. The metric analyzes the ability of the federal system to meet HLH loads on a monthly basis.

> 80-year: HLH energy deficits occur in the winter months as well as late summer; the largest deficit is in the second half of April. This result is consistent over the entire study period. Large monthly HLH energy surpluses occur in the spring, which coincide with the peak Columbia River Basin runoff.
>
> 30-year: The 30-year study presents similar results to the 80-year study, with deficits in April and over the winter months. March in the 30-year period changed to a surplus month, and the surplus in June decreased, consistent with earlier spring runoff. The 30-year study is also showing deeper deficits in the summer and fall consistent with earlier streamflow recessions.

Figure 3: P10 HLH Surplus/Deficits – FY 2024 to FY 2033

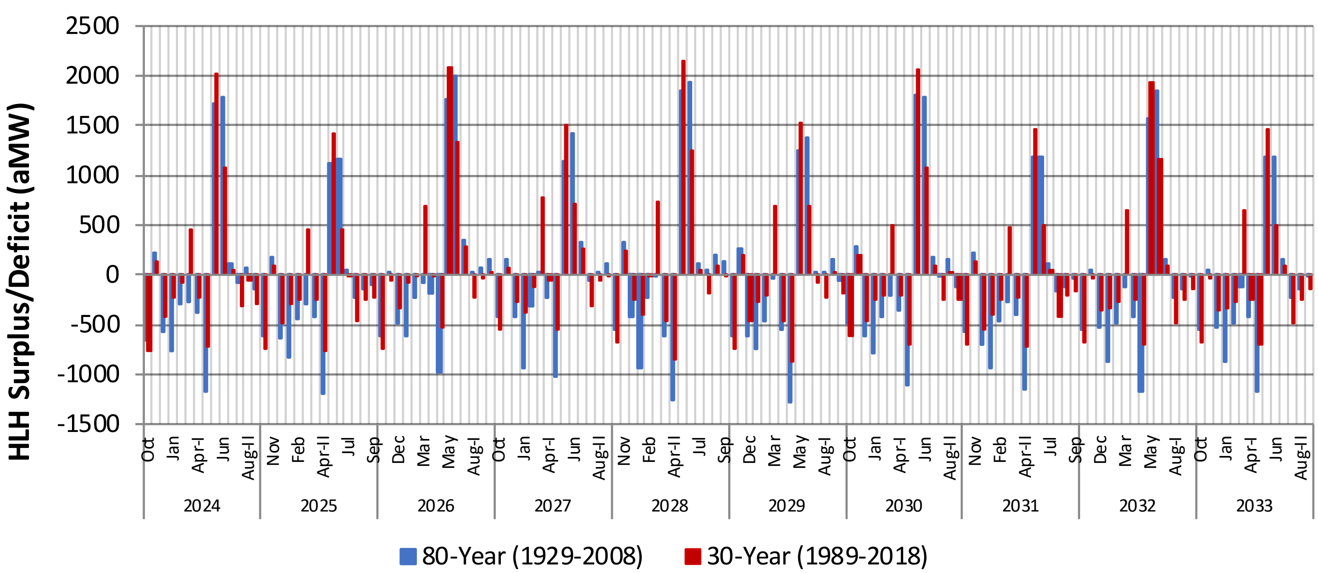
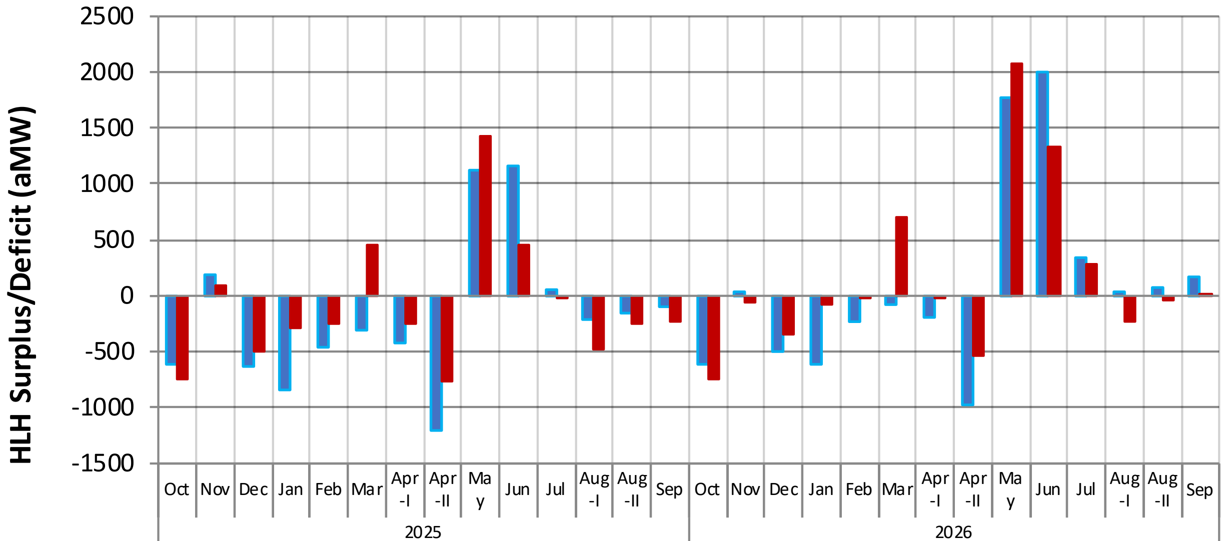


Figure 4: P10 HLH Surplus/Deficits – FY 2025 to FY 2026 (close-up look)



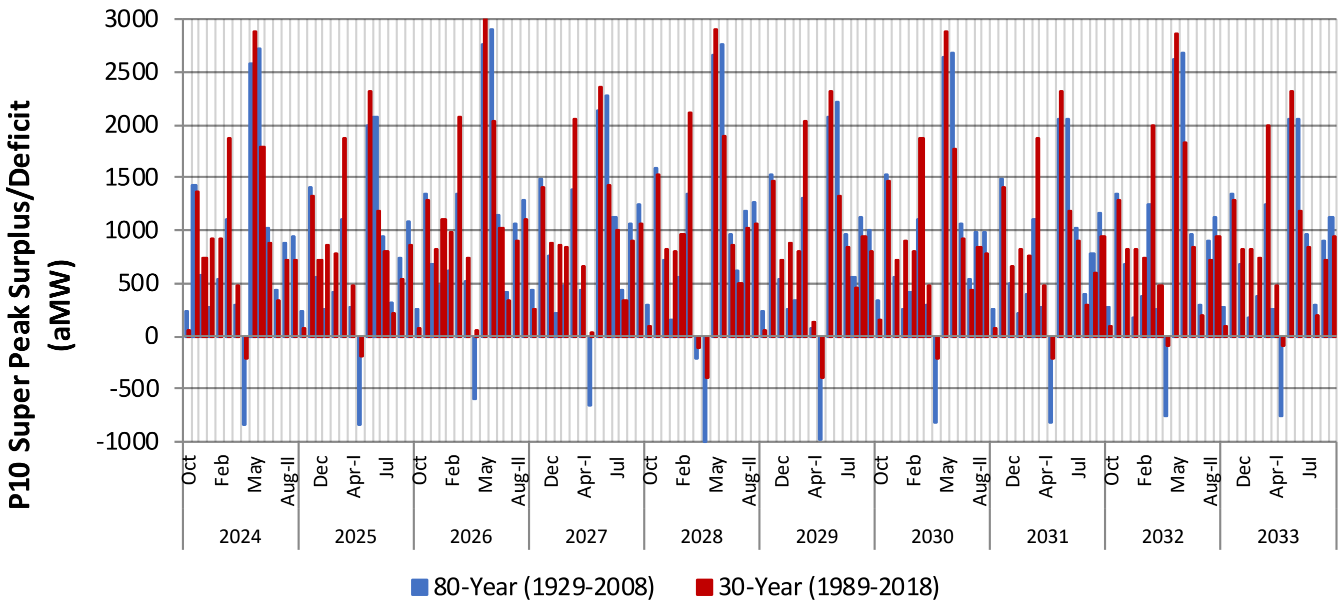
2025	Oct	Nov	Dec	Jan	Feb	Mar	Apr -I	Apr -II	May	Jun	Jul	Aug -I	Aug -II	Sep
80-Year (1929-2008)	-618	185	-640	-836	-453	-299	-425	-120	1120	1159	51	-220	-150	-94
30-Year (1989-2018)	-740	102	-492	-290	-255	464	-248	-761	1421	465	-7	-473	-249	-234

2026	Oct	Nov	Dec	Jan	Feb	Mar	Apr -I	Apr -II	May	Jun	Jul	Aug -I	Aug -II	Sep
80-Year (1929-2008)	-620	30	-497	-620	-226	-69	-189	-979	1767	2008	343	31	70	166
30-Year (1989-2018)	-744	-57	-338	-86	-18	699	-13	-528	2085	1328	280	-226	-35	26

Annual P10 Super-Peak Energy: Figure 5 shows the Monthly P10 Super-Peak Energy metric, which evaluates the ability of the federal system to meet loads over the six peak-load hours per weekday by month.

> <u>80-year</u>: P10 Super-Peak resulted in annual surplus throughout the study period. Monthly analysis shows deficits in April.
>
> <u>30-year</u>: The 30-year study reflects the same finding as the 80-year study, except the April deficit is smaller. The Super-Peak shows similar changes in results as the P10 HLH metric: surplus increases in winter, relative to the 80-year study, and decreases in the summer.

Figure 5: P10 Super Peak Surplus/Deficits – FY 2024 to FY 2033

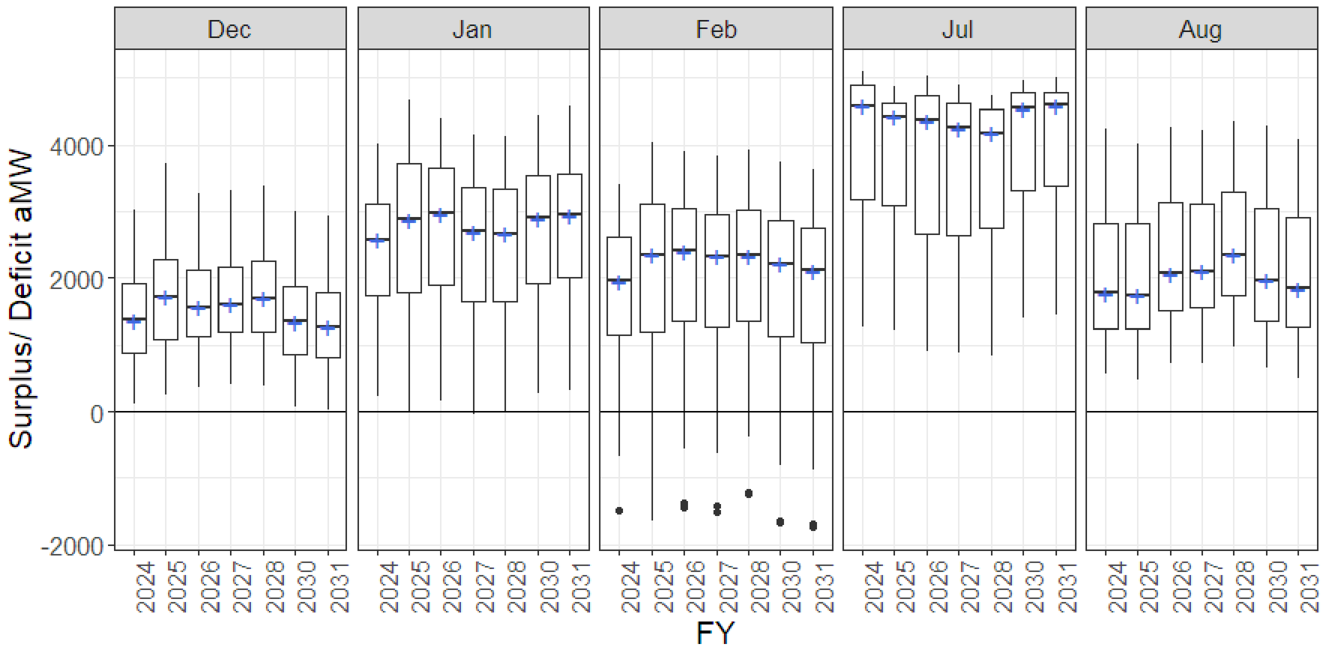


<u>18-Hour Capacity</u>: The 18-Hour Capacity metric analyzes the ability of the federal system to meet loads over the six peak-load hours per day during a three-day extreme weather event – a heat event during summer and cold event during winter – under median water conditions. Only the 80-year study was analyzed under this metric. The months of December, January and February were analyzed for winter seasons; the months of July and August were analyzed for summer seasons. In this Needs Assessment, the extreme weather condition can be viewed for all 80 years, instead of for only a specific year.

Figure 6 presents the distribution of results as boxplots with each end of the box representing the first quartile, or 25%, and third quartile, or 75%, of the data distribution; the middle bar with a blue (+) marks the median, or 50th percentile. The 50th percentile is used to represent the median water conditions for each month. The ends of the whiskers indicate the maximum and minimum data points, and the dark dots outside of the whisker ends are observations outside 1.5x the interquartile range from the bottom of the box, which are the outlier points.

> <u>80-year</u>: Results show 18-Hour Capacity surplus/deficits for the winter (January) and summer (August) during the FY 2024-2033 period; however, there is no data for years 2029 and 2032 as unresolvable data issues were discovered. The 18-Hour capacity results show a range of surpluses between approximately 2,500 MW to almost 3,000 MW in the winter, and a range of roughly 1,700 MW to 2,300 MW in the summer over the study period.

Figure 6: Distributions of 18-Hour Capacity Surplus/Deficits



2.5 Conclusions

The current Needs Assessment shows that BPA would need to supplement existing federal system generation in order to meet existing and projected load obligations during the conditions modeled. With expected load growth, the federal system is projected to have annual energy deficits under critical water conditions across the study period.

Under low-water conditions, the federal system is projected to have HLH energy deficits, most notably in the winter and late summer, and to have surpluses under the Super-Peak and the 18-Hour Capacity metrics. The 18-Hour Capacity metric does not show constraints for either winter or summer seasons. Of the energy and capacity metrics analyzed, HLH energy is projected to have the largest deficits, and therefore, is the most constraining metric.

Under current climate change expectations, the federal system is projected to have lower HLH energy deficits or higher energy surpluses during the winter period. This is due to higher winter streamflows resulting from the warmer temperatures. Conversely, the federal system is projected to have higher HLH energy deficits in the summer due to lower summer streamflows.

Overall, the Needs Assessment results are consistent with that of the 2019 Needs Assessment results with respect to the P10 HLH metric deficits representing the most constrained periods and conditions for BPA to meet its obligations. BPA will continue to assess the need for additional generation based upon potential changes to environmental obligations, participation in the Western Resource Adequacy Program, and the loads placed upon BPA through the Provider of Choice process. Changes to the Needs Assessment in future Resource Programs will include an updated annual energy metric, which will be based on monthly P10 hydropower and potentially include enhancements to how capacity is modeled.

Section 3: Candidate Resource Assessment

3.1 Candidate Generating Resources

The 2022 Resource Program includes an expanded array of zero-emission resources and updated resource costs to reflect developments in renewable generation technologies after the publication of the 2020 Resource Program.

Resources are selected for the optimization based on technical availability within the region and over the study horizon; they are not pre-screened based on relative levelized costs of energy or capacity. The optimization process evaluates the value of expected generation and expected capital in addition to the operation costs of each resource.

The section below summarizes the resource plant types considered for the 2022 Resource Program.

- **Wind:** BPA modeled two types of wind resource, Columbia Basin onshore wind and Oregon coast offshore wind, using costs based on the U.S. Energy Information Administration, or EIA, Annual Energy Outlook,[5] estimates from the National Renewable Energy Laboratory, or NREL, and wind cost forecasts provided by consultants. For Columbia Basin wind, BPA estimated wind output for the forecast period using its risk model designed for rate-setting evaluations in conjunction with Aurora.
- **Solar:** Single-axis tracking utility-scale solar resource costs likewise reflect a blend of EIA, NREL, and consultant cost forecasts and include the latest information on tax credits and tariffs. BPA chose three representative solar generation shapes – southeast Idaho, south-central Washington, and Oregon west of the Portland metropolitan area – to reflect different possible solar output profiles in the BPA region, differing installation costs in metropolitan areas, and a list of locations provided by BPA Transmission Services that may benefit BPA's transmission system.
- **Paired solar and storage:** BPA added three solar and storage resources to the set of available resources for the 2022 Resource Program. The representative generation shapes for these resources are the same as above and are paired with a four-hour battery storage system where capacity is equal to half of the solar nameplate capacity.
- **Standalone six-hour battery storage:** BPA added one standalone battery storage option, modeled as a six-hour lithium-Ion battery system.
- **Zero-emission firm flexible resources:** BPA modeled two zero-emission firm flexible resource options with availability starting in 2028 and later. These resources are not intended to represent a specific generation type, but rather, provide a plausible cost trajectory for several types of zero- or net-zero emissions resources.
    - Base: High-fixed cost, low-variable cost resource. Modeled after small modular nuclear reactor characteristics; also comparable to a traditional fossil fuel base resource with carbon capture and sequestration.
    - Peaker: Low-fixed cost, high-variable cost resource. Modeled after a hydrogen combustion turbine with onsite electrolysis and storage; also comparable to combustion turbine running on other bio/renewable fuels or traditional resources.

[5] https://www.eia.gov/outlooks/aeo/

3.2 Conservation Supply Curves

3.2.1 Overview

Prior to the 2018 Resource Program, BPA had included conservation as a fixed input. In the past, a share of the conservation target from the Northwest Power and Conservation Council's Power Plan was assumed to be achieved by its public power customers. That amount of conservation was included as a predetermined resource that would be applied to meet BPA's needs. The remaining needs would then be met with other potential resources after accounting for expected savings from conservation.

Since the 2018 Resource Program enhancements, BPA now assesses conservation in line with other available supply and demand-side resources. An available amount of conservation is input into the optimization model, which then compares and selects resources based on need, availability and cost. To determine the amount of conservation to be used in the optimization model, BPA relies on a conservation potential assessment (CPA). The CPA identifies the amount and costs of energy efficiency measures available from the forecasted customer loads supplied by BPA over the planning horizon. This ensures all potential conservation is included and evaluated against competing alternatives in the optimized selection process.[6] In preparation for the 2022 Resource Program, BPA contracted with Cadmus Group and Lighthouse Energy Consulting to conduct a CPA.

3.2.2 Adjusting for 2022 and 2023 Energy Efficiency Accomplishments

While the Resource Program's evaluation period begins with 2024, the load forecast developed by BPA for use in the Resource Program was developed in 2020 and does not incorporate future energy efficiency savings achieved by BPA and its customer utilities in 2020-2023. To ensure that the Resource Program properly accounted for BPA's loads and resources, BPA's Energy Efficiency Organization supplied the Resource Program team with adjustments to account for the additional savings that would be achieved in these years. The adjustments were provided as "must take" resources—resources the Resource Program was forced to select, since they reflected energy efficiency that would be accomplished by 2024.

For the portion of 2020 not included in BPA's load forecast and all of 2021, the Cadmus/Lighthouse team mapped BPA's actual accomplishments to load profiles and developed hourly inputs for the Resource Program.

For 2022 and 2023, the CPA potential was not provided to the Resource Program. In its place, the Cadmus/Lighthouse team provided hourly estimates based on BPA's overall expected level of savings mapped to different distributions of savings. Forecasts developed by BPA projected 37.85 average megawatts per year of energy efficiency. The Cadmus/Lighthouse team used the distribution of BPA programmatic achievements in 2021 to estimate the distribution of savings in 2022 and the distribution of CPA potential in 2024 below a levelized cost of $45 per megawatt hour for 2023.

Incorporating these adjustments developed a more accurate forecast for the potential conservation savings starting in 2024, the beginning of the 2022 Resource Program's evaluation period.

[6] The full CPA, including methodological discussion, is available on BPA's website: BPA-Conservation-Potential-Assessment-2022-2043.pdf

3.3 Demand Response Supply Curves

Since the 2018 Resource Program, BPA also assesses demand response equivalent to other available supply and demand-side resources. As with conservation, available amounts of demand response are input into the optimization model, which then compares and selects resources based on need, availability and cost. To determine the amount of demand response to be used in the optimization model, BPA relies on a demand response potential assessment (DRPA). The DRPA ensures all potential demand response is included and evaluated against competing alternatives in the optimized selection process.

In preparation for the 2022 Resource Program, BPA contracted with Cadmus Group and Lighthouse Energy Consulting to conduct a DRPA. The assessment identified 19 DR products with distinct cost and seasonal profiles. The full potential assessment, including methodological discussion, is available on BPA's website[7].

3.4 Wholesale Energy Market

3.4.1 Wholesale Market Price Forecast

Bonneville used Aurora with the Western Interconnection, a zonal topology, to generate a 10-year forecast of Mid-Columbia prices. This forecast consists of a distribution of 400 risk-informed hourly forecasts sampled two weeks per month.[8] Each of the 400 forecasts is based on a unique water year sequence, natural gas price forecast, Western Electricity Coordinating Council-wide load forecast, hourly wind generation pattern, Columbia Generating Station outages schedule and hourly transmission path rating, as applied to the alternating current, direct current and British Columbia-United States interties. The price at a given energy hub is determined by the cost of delivering an incremental megawatt of energy to load, including transmission costs and energy losses, provided by the least-cost available resource.

The WECC load forecast is consistent with BPA's 2020 baseline projection, except for California, which has been updated to be consistent with California Energy Commission's 2019 Integrated Energy Policy Report's Mid Demand-Mid Available and Achievable Load Forecasts.[9]

Natural gas prices are typically a significant determinant of electricity prices because gas generators tend to be the marginal unit, or the least-cost generator available to supply an incremental unit of energy, and the price of natural gas is the predominant factor affecting the dispatch, or production, cost of natural gas-fired generators. Relative to the 2020 Resource Program, there were modest declines in projected natural gas prices over the forecast horizon. The declines are a result of the expectation for plentiful production of low-cost associated gas produced by oil-focused extraction activity.

Several processes inform BPA's forecast of WECC-wide resource retirements and builds used in the price forecast and market depth studies. First, data from the EIA's database of planned and sited resource additions and retirements over the horizon of the BP-22 rate period were referenced against additional data from sources such as BPA's Transmission Interconnection Queue, WECC's Transmission Expansion

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[7] https://www.bpa.gov/-/media/Aep/energy-efficiency/demand-response/bpa-demand-response-potential-assessment-2022-2043.pdf

[8] For more information about Aurora and the risk models employed to produce this forecast, see the Power Market Price Study and Documentation, BP-22-FS-Bonneville-04.

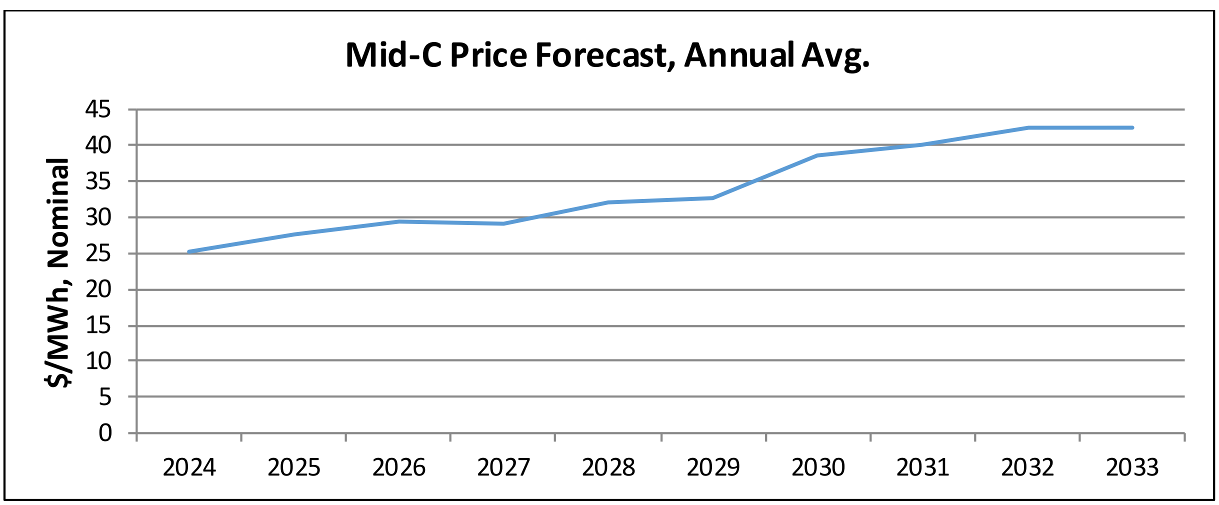
[9] https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-03, accessed Mar 2, 2021.

Planning Policy Committee, the California Energy Commission, the California Public Utilities Commission, and third-party consultant reports to update the default Aurora resource stack. Additionally, estimated levels of behind-the-meter, rooftop solar photovoltaic additions in California were included from the California Energy Commission forecast and from integrated resource plans of utilities in the Southwest. Finally, the Aurora long-term capacity expansion model was used to build and retire additional resources based on economics to satisfy pool planning reserve margins and meet all relevant state, municipal and utility policies, including renewable portfolio standards, zero emission targets and electric sector emission caps.[10]

BPA's Aurora price forecast also adds two adjustments to resource bidding behavior that have substantial impacts on the resulting distributions of price forecasts. First, BPA runs Aurora using a recent historical period, i.e., 2014-2019, and calibrates thermal resource bidding behavior to better align Aurora prices with actual, day-ahead hub prices during the period. Second, BPA includes a simplistic depiction of negative bid behavior for renewable resources driven, for instance, by federal production tax credits for wind resources, renewable energy credits and power purchase agreements. All WECC renewable resources are given bid adjustments of about -$23 per megawatt-hour, which is nominal. These assumptions and additional modeling enhancements, such as the use of Aurora's commitment optimization logic, resulted in a distribution of price forecasts that is higher than the price distribution used in the previous Resource Program. The main driver for higher prices is the combination of a tighter resource buildout, where reliability requirements are just barely met, and the addition of calibrated thermal resource bidding behavior. Price increases are most acute in summer and winter months and in iterations with low hydro conditions.

The following figures depict the Mid-C price forecasts. Figure 7 shows an annual average price for all hours by year. Figure 8 presents average monthly prices for all hours by each month for the years 2024, 2028 and 2032. Figure 9 depicts prices averaged by hour for the years 2024, 2028 and 2032. Figure 10 is a comparison between the Mid-C price forecasts for the 2020 and 2022 Resource Programs for heavy load hours (HLH) and light load hours (LLH).

Figure 7



[10] State policy requirements within the WECC enacted as of July 1, 2021. Additional clean energy goals and policies at the municipal and utility level are included, but have been discounted by 20% to represent uncertainty about the extent to which these commitments will be upheld over the forecast horizon.

Figure 8

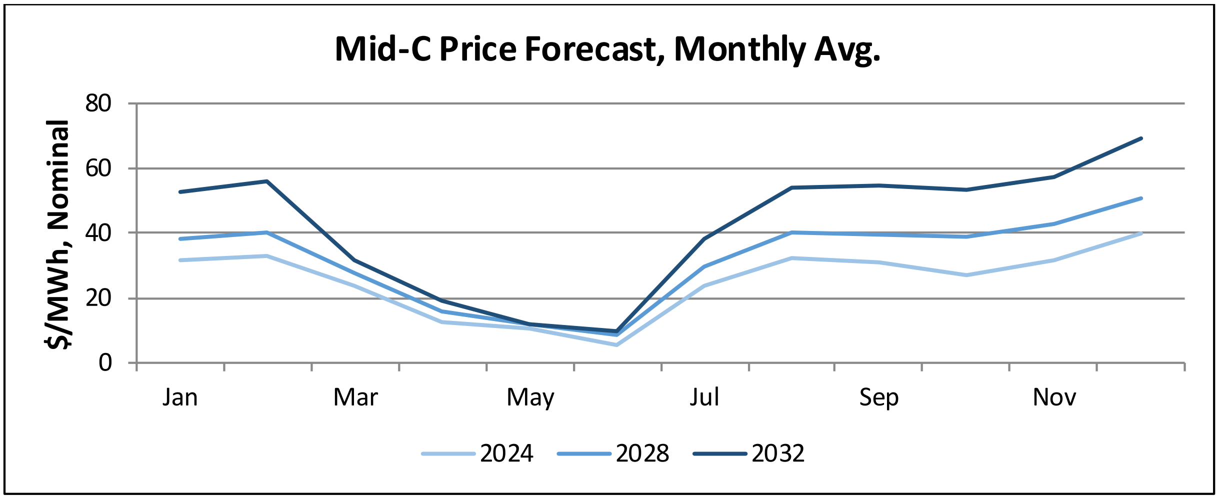


Figure 9

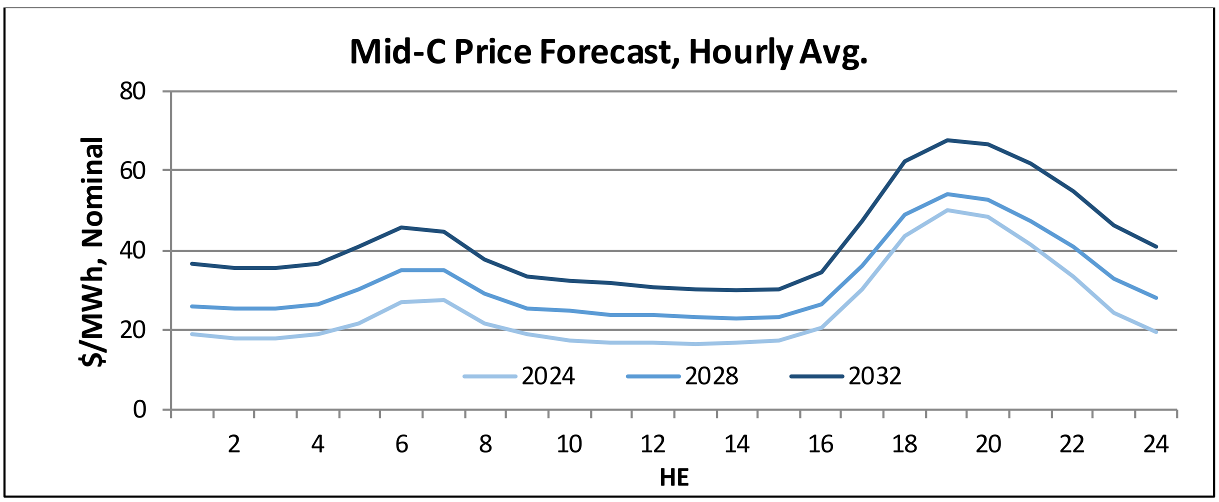
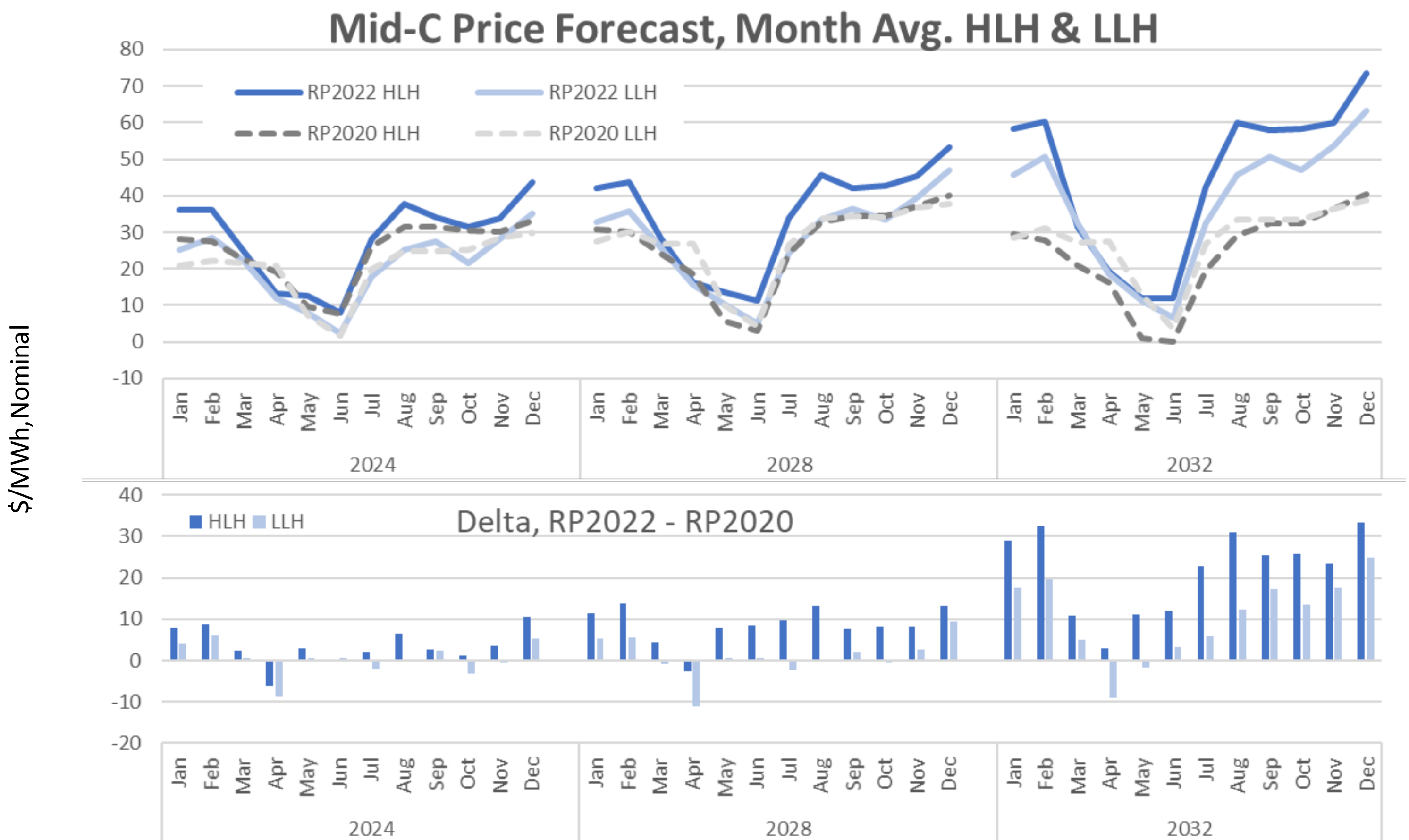


Figure 10



3.4.2 Market Reliance Limit

Given expected fundamental changes in energy markets across the WECC driven by growth in zero-emission resources, BPA used Aurora to assess future energy availability and establish monthly market reliance limits for the 10-year planning horizon. The process begins with a resource build assumed to reflect zero market reliance, i.e., all balancing authorities meet their reliability needs individually, without relying on other BAs or regions. Next, BPA uses incremental reductions in regional resources[11] to represent increases in market reliance. Higher levels of market reliance are tested until the exceedance of the 5% loss-of-load probability threshold. Up until that point, it is assumed that the region can rely on market exchanges to meet energy needs rather than building or maintaining additional resources. BPA is then allocated a share of the market availability proportional to its share of regional load. This sets BPA's market reliance limit, expressed in terms of monthly average heavy-load-hour megawatts. It should be noted that this methodology does not anticipate or account for evolving market structures, such as wider adoption of an Energy Imbalance Market or a WECC-wide Independent System Operator. The estimate simply reflects expected physical energy availability given projections of WECC load-resource balance and transmission capabilities.

[11] Testing all combinations of resource removal would be computationally prohibitive; instead, BPA uses monthly flat load increases to represent the loss of resource availability.

Section 4: Resource Optimization

4.1 Overview

The Bonneville Power Administration uses Aurora to calculate least-cost and risk-reducing[12] resource options that satisfy its needs throughout the 10-year planning horizon. These portfolios further inform BPA's resource strategy, including information on the amount of Energy Efficiency Incentive funding, which may be invested over the upcoming rate period.

4.2 Long-term Capacity Expansion

The 2022 Resource Program added a resource optimization step using the Aurora long-term capacity expansion study type. This study uses an iterative mixed-integer program to solve for the least-cost set of resource options that meet BPA's 10th-percentile, or p10, heavy load hour needs. It does so at greater granularity than the portfolio optimization and ensures that existing resources and new selections are meeting system energy and capacity obligations, if present.

While the portfolio optimization study optimizes over the distribution of 400 traces at the monthly diurnal level, the long-term capacity expansion, or LTCE, uses hourly granularity for the resources available to meet BPA's p10 HLH obligations. This allows a more precise optimization of least-cost resource strategies while using more detailed market costs and availability, generation resource output profiles and cost, and energy-efficiency and demand-response savings profiles and costs. The least-cost resources built in the LTCE meet BPA's p10 HLH obligations and are then fed to the portfolio optimization study as "must-build" resources. The portfolio optimization will then evaluate these resources according to the varying loads, resources, market prices and applicable wind risk in each of the 400 traces in the input distribution. Portfolio optimization then uses the performance of each resource in each run to conduct the portfolio analysis.

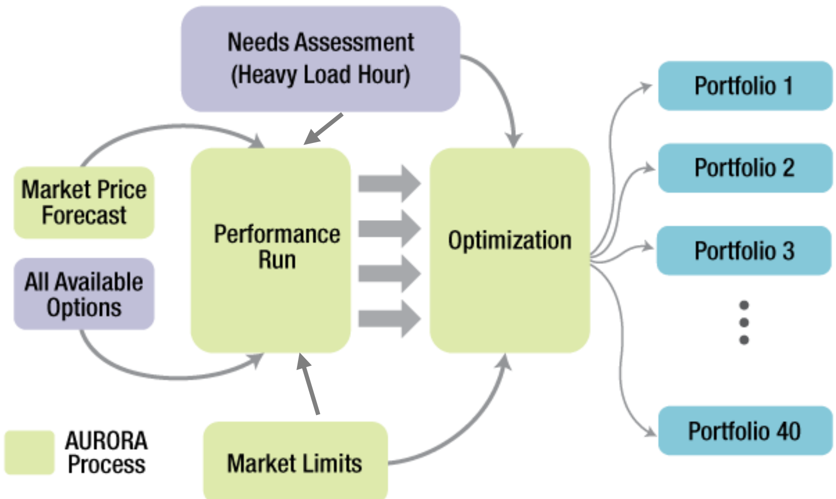
4.3 Portfolio Optimization

Figure 11 depicts the overall process and key inputs for the portfolio optimization study. Resource Program staff begin by evaluating all resource options discussed in Section 3 to assess their individual performance in each of the 400 sets of inputs. The 400 zonal runs, called the performance runs, each contain a different mix of needs, market prices, gas prices and wind risk and allow the portfolio optimization study to evaluate each resource according to those differing conditions.

Market reliance limits are also applied in the 400 zonal runs via a second zone that represents the Mid-C hub as well as transmission links between the BPA zone and the market zone that correspond to the monthly HLH market reliance limit. These limits also serve as constraints for the optimization step.

[12] "Risk" is defined here as variation of total portfolio costs across the 400 market price forecasts; see market price forecast, Section 3.4).

Figure 11



Aurora employs a linear optimization to jointly solve for the least-cost solution of meeting energy needs over the 10-year planning horizon – or Portfolio 1 – subject to market costs, market reliance limits and resource constraints. Portfolio 1 is selected by lowest average cost, over the 10-year study horizon, across the 400 price sets without considering the variance in portfolio cost across the 400 iterations. The model then solves for portfolios that minimize variation of total portfolio costs at progressively higher total portfolio cost levels on average.[13] The risk-minimizing portfolios can be thought of as hedges against market price volatility or streamflow conditions, or both. Each successive portfolio has a higher budget constraint and allows for the purchase of more resources that are not least-cost but provide greater insulation against market price swings or streamflow conditions.

This results in a series of portfolios that create an efficient frontier, as demonstrated in Figure 12. The frontier is efficient in the sense that at any given cost point, there is no other combination of available resources that would reduce the variation of total portfolio costs. Therefore, all portfolios above the efficient frontier are suboptimal because their costs can either be reduced without an increase in variance, or their variance can be reduced without an increase in cost. Alternatively, both cost and variance can be reduced to arrive at a better performing portfolio.

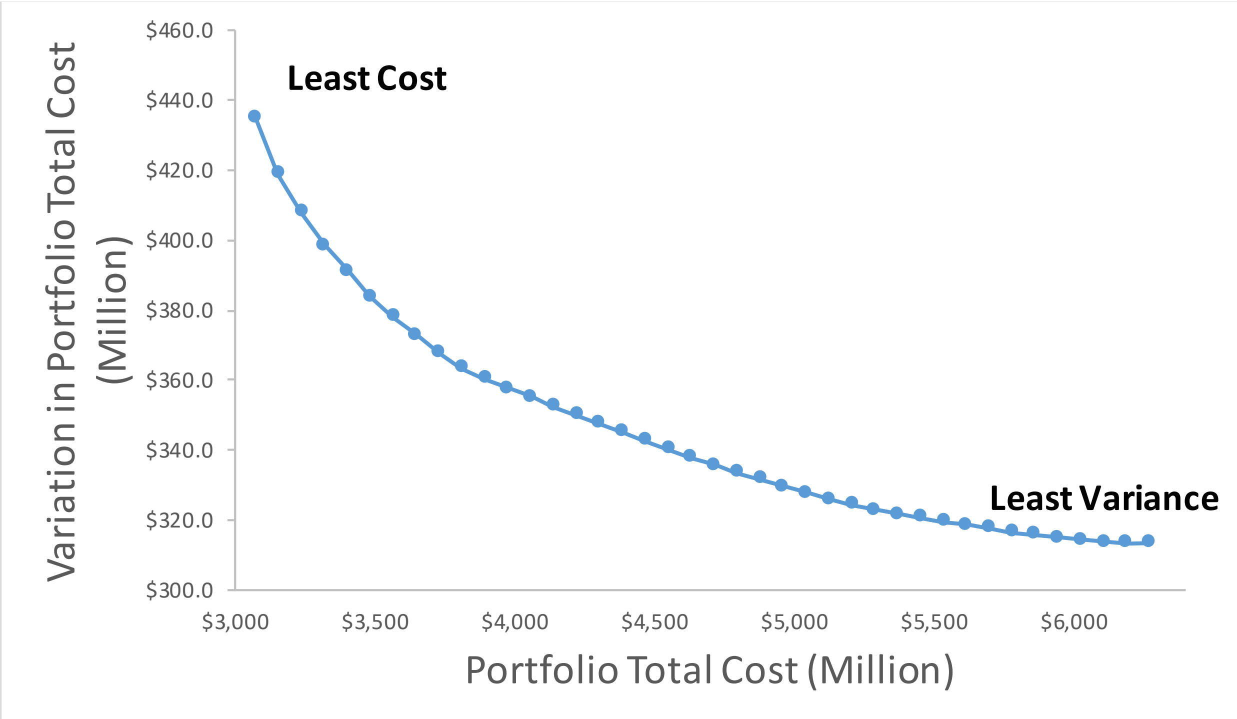
4.4 Portfolio Optimization Results

The Aurora portfolio optimization process produces an efficient frontier with 40 different resource portfolios. Figure 12 shows the model output of the 40 different portfolios for the 2022 Resource Program. These results are characterized by diminishing returns to the risk-reducing portfolios – the

[13] After finding the least-cost portfolio, the optimization model then solves for a portfolio with the lowest total cost variation, in terms of total portfolio cost standard deviation, without regard for total cost level, known as Portfolio 40. These two portfolios become end points of an efficiency curve. The range of average total portfolio cost is then split up according to the number of desired portfolios - BPA selected 40. For each point along this range, the optimization model solves for a portfolio of resources that minimizes total portfolio variation without exceeding that particular total cost level.

greatest reduction in variance is from the first portfolio to the second, and each successive portfolio achieves a smaller decrease than the last.

Figure 12



Given the changes in resource costs, BPA's loads and resources, the market prices forecast and market purchase limit, results have shifted from the 2020 Resource Program. The Resource Program team also made a number of improvements to the Aurora model that is used for the Resource Program analysis. The primary drivers of the difference from the prior Resource Program are as follows.

1. **Updated water years in the needs assessment:** The set of water years used to calculate BPA's p10 HLH needs has been updated since the prior Resource Program. The agency now bases its forecasts on the 30 water years between 1989 and 2018 rather than the 80 water years comprising the 1929 to 2008 period. This updated set of historical streamflows better captures the impacts of climate change on BPA's system and results in a shift of the monthly period with the greatest needs from January HLH to October HLH.
2. **Improved resource selection:** Refinements to the Aurora model for the 2022 Resource Program, in comparison to the 2020 Resource Program, allow resource selection in any year, rather than in one year, for energy efficiency and demand response, or two years, for generating resources. This allows the model to consider the cost effectiveness of each resource in each year, rather than the overall cost effectiveness of each resource across the entire study horizon. The main effect of this is that resource selections are lower in the initial years, approximately the same in the middle years, and substantially higher in the later years in comparison to the prior Resource Program as resource selections ramp up to meet load growth beyond 2029.
3. **Higher market price forecast:** On average, higher market prices make energy purchases more expensive and surplus energy more valuable. In general, because purchases tend to be made in expensive hours, higher market prices lead to higher overall portfolio total cost while also

increasing the opportunity for energy efficiency and demand response to be less expensive than market purchases.

In the basecase for the 2020 Resource Program, all 40 portfolios contained only energy efficiency and market purchases. For the 2022 Resource Program, in addition to energy efficiency and market purchases, demand response was also selected in all 40 portfolios, and generating resources were selected in portfolios two through 40.

Table 1 shows the energy efficiency acquisitions in the three lowest-cost portfolios. Compared to the 2020 Resource Program, energy efficiency acquisitions in the least-cost portfolio are slightly lower in the first two years of the 2022 Resource Program, but ramp up quickly, acquiring nearly 200 aMW more energy efficiency by the final year of the study than the 2020 Resource Program.

Table 1. Energy Efficiency Acquisitions of the Lowest-Cost Portfolios

	Cumulative Energy Efficiency Acquired (aMW)		
Portfolio	2-Year	4-Year	10-Year
1	96	223	723
2	103	242	785
3	105	245	787

Table 2 and Table 3 show the DR and generating resource selections in the three lowest-cost portfolios.

Table 2. Demand Response Acquisitions of the Lowest-Cost Portfolios

	DR Acquired (Peak MW)					
Season	Summer			Winter		
Portfolio	2-Year	4-Year	10-Year	2-Year	4-Year	10-Year
1	213	436	371	158	283	243
2	213	474	488	158	283	260
3	213	474	488	158	283	260

Table 3. Generating Resource Acquisitions of the Lowest-Cost Portfolios

	Generating Resource Solutions					
Resource	Offshore Wind (Nameplate Capacity, MW)			Solar PV (Nameplate Capacity, MW)		
Portfolio	2 Year	4 Year	10 Year	2 Year	4 Year	10 Year
1	0	0	0	0	0	0
2	0	0	106	0	0	500
3	0	0	428	0	0	500

4.5 Conclusions

The resource solutions produced by portfolio optimization and detailed in section 4.4 indicate that the most economical solution for BPA to meet its energy obligations continues to be a combination of market purchases and demand-side resources. Energy efficiency and low-cost demand response were acquired in the least-cost portfolio up until it was as expensive as market purchases, and then the optimization solved for the remaining needs with market purchases. Low-cost energy efficiency remains BPA's preferred resource to meet identified energy needs.

The demand response resources were selected to meet short-duration energy needs in the months with the highest market prices. BPA did not identify a capacity need in the Needs Assessment, so these demand response resources are being dispatched to satisfy short-duration energy needs in the most expensive hours.

It is important to note that while the Needs Assessment looks at Bonneville's loads and resources in isolation, other regional studies have identified future capacity shortfalls in meeting the entire Pacific Northwest's load. BPA's system is expected to have surplus capacity, which is anticipated to become increasingly valuable as thermal generation continues to be retired from the grid in accordance with de-carbonizing legislative goals.

Additionally, the Needs Assessment does not analyze the use of the federal system to provide balancing services for variable energy resources. Instead, it specifically retains the federal system's capacity for service to BPA's statutory obligations. These and other issues are addressed in separate forums; the 2022 Resource Program results should not be viewed as representing the capacity needs for the entire region or any other specific entities within it.

Section 5: High Policy Scenario

5.1 Purpose

The Bonneville Power Administration modeled a high policy scenario in addition to the basecase. This scenario represents a plausible high electrification and decarbonization case while also providing a look at the least-cost resource builds that would be required to meet BPA's obligations in such a future.

The Resource Program team does not place any specific likelihood on the high policy scenario assumptions occurring. BPA will continue to monitor future load growth; should conditions such as those assumed in the high policy scenario begin to materialize, the high policy scenario enables the agency to adapt its resource strategies accordingly.

5.2 Assumptions

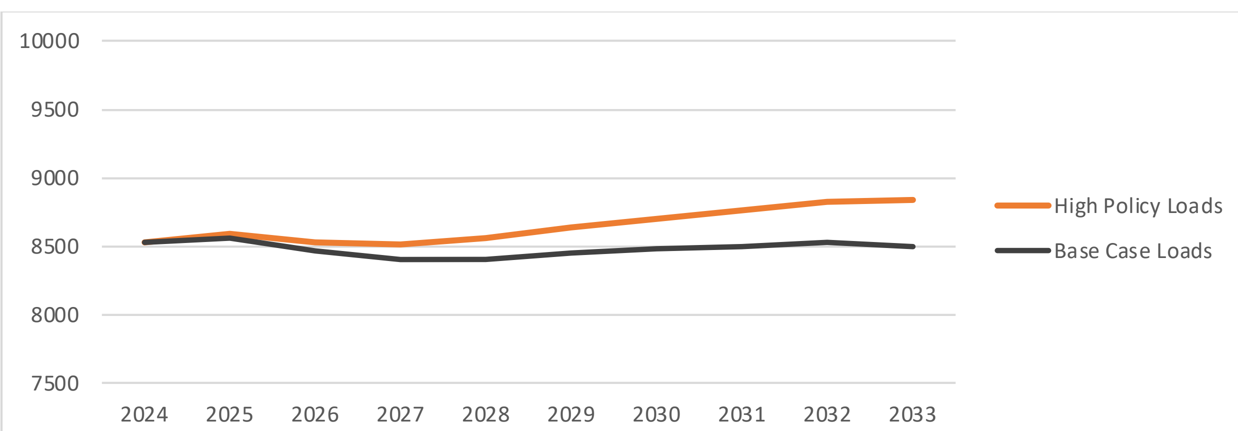
The high policy scenario represents a possible outcome given accelerated electrification and decarbonization policies in the western U.S. In this scenario, California carbon pricing is applied to Oregon and Washington, Western Electricity Coordinating Council-wide carbon pricing begins in 2030, and all states aim for 100% zero-emissions by 2050. Specific changes to the basecase assumptions are detailed below.

5.2.1 Obligations

The Resource Program team escalated the basecase distribution of BPA's monthly heavy load hour obligations using regional load growth rates provided by BPA Load Forecasting. The high policy load forecast assumed no change in the BPA customer base post-2028. It does assume accelerated adoption rates for electrification technologies and practices, such as electric vehicles, behind-the-meter solar and fuel switching from gas to electricity.

Excluding large new loads, which would be served at the New Resource rate, BPA estimated average annual growth of 0.43% over the study horizon. This results in roughly 4.5% growth over the basecase for the 10 years in the study horizon. The growth over the basecase is shown in Figure 13.

Figure 13



5.2.2 Resources

The Resource Program team made small reductions to the cost of renewable resources and battery storage for the high policy scenario. These adjustments reflect policies in the high policy scenario designed to facilitate the adoption of renewable generation and energy storage technologies.

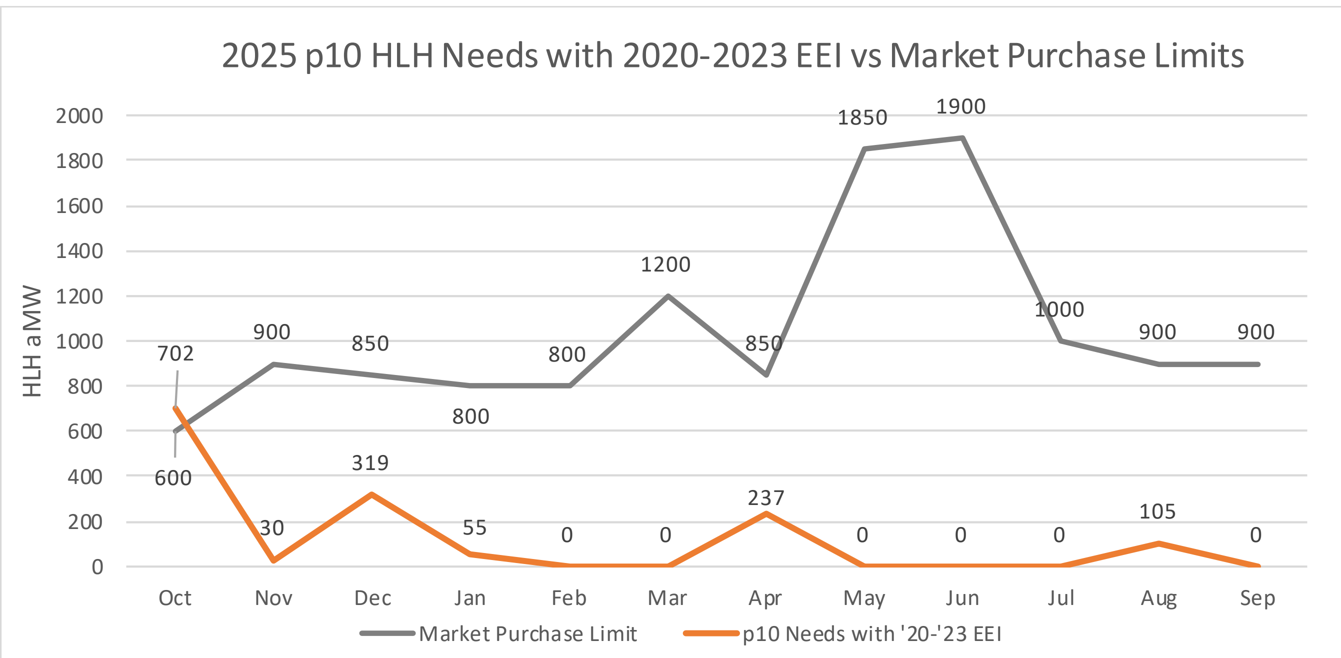
5.2.3 Market Prices and Limits

The policies associated with the high policy scenario result in a decrease in the overall market price forecast for the high policy scenario versus the basecase. Market prices are also lower in the high policy scenario during both January and October heavy load hours across the study horizon. January HLHs are typically characterized by higher-than-average market prices, and October HLHs have the greatest deficit between BPA's needs and market purchase availability. Periods with high market prices and periods with low market availability but high system needs will influence the resources selected in the portfolio analysis.

5.3 Results

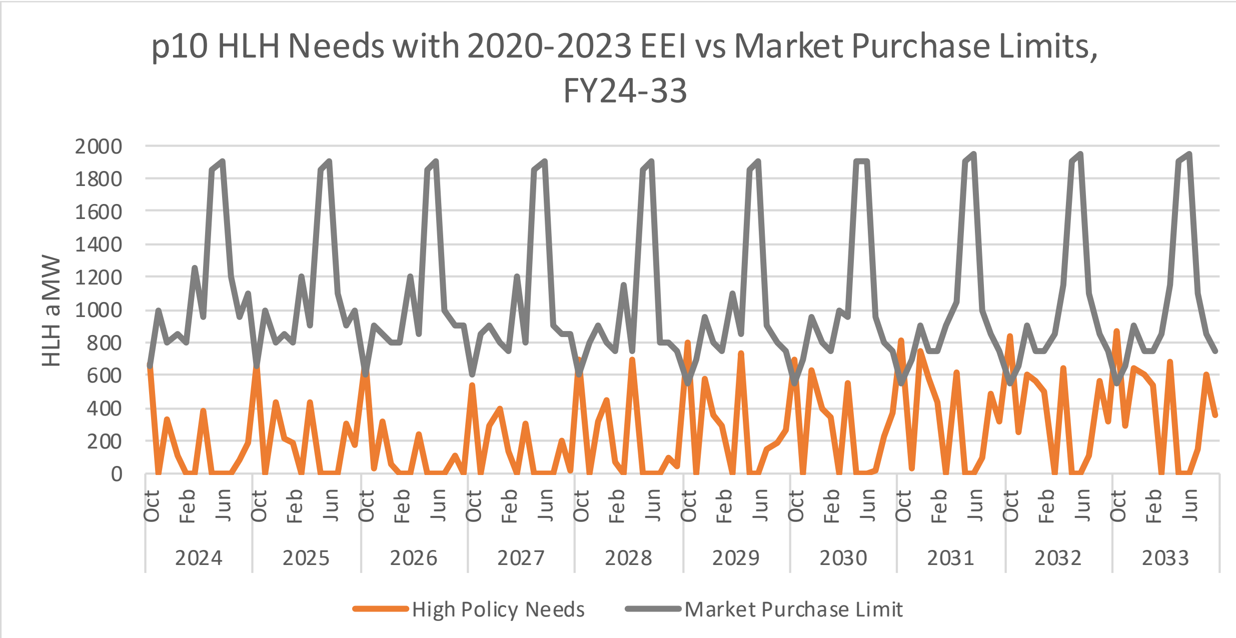
The increase in obligations for the high policy scenario caused the difference between BPA's October HLH needs and October HLH market purchase limit to increase to 102 average megawatts by fiscal year 2025, the second year of the study; see Figure 14.

Figure 14



This pattern continues later in the study, where the growth in BPA's obligations increases the difference between Bonneville's needs and the market purchase limit in every year from 2028 onward; see Figure 15.

Figure 15



Months where BPA's needs exceed the market purchase limit are months where the model will acquire resources above market purchases in the resource stack. It will have already acquired all resources that are cheaper than the market before moving to market purchases. Once the market purchase limit is exhausted, the optimization must add one or more resources that meet the remaining need for that month.

Table 4, Table 5 and Table 6 show the high policy scenario resource builds for conservation and generation resources for the three lowest-cost portfolios.

Table 4. High Policy Scenario Energy Efficiency Acquisitions of the Lowest-Cost Portfolios

	Cumulative Energy Efficiency Acquired (aMW)		
Portfolio	**2-Year**	**4-Year**	**10-Year**
1	95	221	696
2	98	229	755
3	102	238	786

Table 5. High Policy Scenario Demand Response Acquisitions of the Lowest-Cost Portfolios

	DR Acquired (Peak MW)					
Season	Summer			Winter		
Portfolio	2-Year	4-Year	10-Year	2-Year	4-Year	10-Year
1	213	437	373	176	336	269
2	213	475	490	176	336	283
3	213	513	492	176	336	303

Table 6. High Policy Scenario Generating Resource Acquisitions of the Lowest-Cost Portfolios

	Generating Resource Solutions					
Resource	Offshore Wind (Nameplate Capacity, MW)			Solar PV (Nameplate Capacity, MW)		
Portfolio	2 Year	4 Year	10 Year	2 Year	4 Year	10 Year
1	0	31	31	42	42	42
2	0	31	31	212	212	462
3	0	56	105	250	250	750

5.4 Discussion and Comparison

Energy efficiency and demand response acquisitions in the high policy scenario are little changed from the basecase. In both cases, energy efficiency and demand response resources are acquired up to the point that the marginal resource is no cheaper than market purchases. The 102-aMW gap between the market purchase limit and BPA's needs in early FY 2025 is too sizeable to be filled with energy efficiency and demand response alone. This, coupled with the reduction in cost for renewable resources, led to the acquisition in 2025 of some additional winter demand response and a small amount of solar photovoltaic (PV) resources.

The continued growth of BPA's load obligations from 2027 onward also supports the acquisition of a small amount of generation with an output profile similar to offshore wind. The need to acquire generating resources in the early and middle years of the study period, combined with the lower market price forecast in the high policy scenario – which influences every resource's expected revenue – results in a small amount of substitution from energy efficiency to renewable generation compared to the basecase.

This substitution occurs mostly in the later years of the study. Up through 2029, there is little difference in energy efficiency acquisitions from the basecase. In 2029, energy efficiency acquisitions in the high policy scenario are just four aMW lower than the basecase. By 2033, energy efficiency acquisitions are roughly 25 aMW lower than in the basecase.

It is also worth noting that both the basecase and high policy scenario for the 2022 Resource Program have substantially higher energy efficiency acquisitions in the later years than in the 2020 Resource Program. The 2020 Resource Program acquired more energy efficiency in the first two years, nearly the same amount over four years, and a much lower amount overall than either scenario in the 2022 Resource Program.

In 2020, the least-cost portfolio contained just over 500 aMW of energy efficiency by the last year of that study. In 2022, the basecase acquires approximately 215 aMW more energy efficiency over the study period, and the high policy scenario acquires 190 aMW more when compared to 2020. Table 7 below presents the least-cost portfolio for 2-, 4- and 10-year cumulative energy efficiency acquisitions from both resource programs.

Table 7: Comparison of 2022 Energy Efficiency Acquisitions to 2020 Resource Program

	2-year	4-year	10-year
2020 Resource Program	111	229	506
2022 Resource Program - Base	96	223	723
2022 Resource Program - High Policy	95	221	696

Section 6: Action Items

6.1 Next Steps

In the coming months, BPA will publish its Energy Efficiency Action Plan (Action Plan), describing its conservation goals, portfolio management strategy and program measures. The Action Plan will be informed by the Council's 2021 Power Plan, BPA's Resource Program and Integrated Program Review. BPA will also consider customer needs and other benefits of conservation such as capacity, resiliency and avoided emissions. During the Action Plan development process, low-cost flexible load management solutions that can be frequently deployed with minimal customer impacts will also be assessed.

Looking toward the next Resource Program, BPA plans to further develop and refine the enhancements it has made for the 2022 Resource Program, including updates to energy storage and demand response modeling, and refinements to the optimization process and risk analysis.

BPA will also monitor events that could change the forecasted outcomes of the 2022 Resource Program, such as new clean energy legislation, changes to resource costs or loads, or as yet unforeseen changes to the operations of the Federal Columbia River Power System. The impacts of these and other events, as well as anticipated modeling enhancements and improved information and data that become available, will be incorporated into future planning activities.

Section 7: Transmission Supplement Summary

The Bonneville Power Administration's Transmission Services organization is instrumental to ensuring BPA Power Services' existing generating resources and market purchases are delivered to load in the BPA balancing authority area. Therefore, including a Transmission Supplement is intended to show the deliverability aspect, not just the generation aspect, of how BPA approaches resource adequacy for its obligations. BPA also relies heavily on other regional utility transmission providers to ensure that Power Services' load is served in balancing authority areas outside of BPA's. That portion of deliverability is not described in this Transmission Supplement.

If and when Power Services identifies and pursues the acquisition of resources other than energy efficiency and potentially demand response, Power Services would have to actively coordinate with Transmission Services. Such resource acquisitions are, however, unlikely in the near-term based on the results of the 2022 Resource Program analyses. Power Services and Transmission Services do actively coordinate and collaborate on near-term and long-term system planning activities, including model inputs, load forecasts, resource retirement estimates, and several other planning topics of mutual interest. Expanded active coordination would occur if Power Services resource acquisitions beyond demand side resources occurred. For a detailed description of Transmission's planning processes, read the Transmission Supplement attached in the Appendix.

Section 8: Appendix: Transmission Supplement Continued

This section was provided by the Bonneville Power Administration's Transmission Services organization. It describes the transmission planning process in Transmission Services and how the organization collaborates with BPA Power Services to serve the long-term transmission needs of network transmission, or NT, and point-to-point, or PTP, customers. It also describes how its available transfer capacity, also known as ATC or transmission inventory, is managed to respond to customer requests for long-term transmission service. Transmission Services and Power Services work and collaborate closely to manage the hydro resources of the Federal Columbia River Power System to serve the needs of BPA's NT customers. Besides Power Services, Transmission Services has a wide range of customers for PTP transmission services to deliver power from regional resources to many bulk electric power customers.

The chapter starts with an overview of BPA and its strategic objectives. It then reviews the trends Transmission Services believes will most affect its future: decarbonization, decentralization, technology, regulatory reform and regional cooperation. Each of these brings risks and opportunities to consider in the analytical, modeling and decision-making part of the process.

The analytical process starts with Transmission Planning having a good understanding of NT and PTP customers and their needs and load growth patterns. Transmission Planning also reviews resources, customers' technology, fuel prices, government policy and more. Forecasted loads and resources are the basis for transmission planning in addition to existing obligations and committed long-term firm transmission service.

Once the system conditions are defined, the analysis turns to developing corrective action plans for problem areas not meeting the applicable reliability standards. Finding solutions for these problem areas requires multiple analytical tracks: (a) consideration of non-wires solutions in cooperation with cross-agency organizations at BPA; and (b) coordination with Power Services and multiple organizations in Transmission Planning to collaborate on integrated solutions.

Once Transmission Services completes the system assessment, including the proposed transmission corrective action plans and flowgate ATCs, the capacity becomes eligible to meet the needs of BPA customers who submit Transmission Service Requests for transmission capacity for their loads and resources. The TSRs are then combined for the cluster study's needs assessment, which serve as load scenario conditions for the cluster study. In the cluster study, the network is analyzed to define reinforcements and non-wire solutions necessary to serve the TSR needs. Customers are then informed so they can make their project decisions, proceed to contract negotiations and ultimately to construction. Throughout the planning process, Transmission Services and Power Services work closely in a joint process called Agency Integrated Planning. The AIP process ensures a high level of coordination among the different groups in Transmission Services and Power Services to achieve an efficient data collection, analytical evaluation and optimal recommendations.

8.1 Introduction

BPA energizes the region through more than 15,000 circuit miles, or 24,000 kilometers, of transmission lines and 261 substations in the Pacific Northwest, controlling approximately 75% of the high-voltage transmission system in the region. BPA also maintains interconnections with other regional power grids: British Columbia to the north; Rocky Mountains, Idaho and Montana to the east and southeast; and California to the south. BPA shares two interties with California: (a) the California-Oregon Intertie with northern California utilities; and (b) the Pacific DC Intertie with the Los Angeles Department of Water and Power.

Transmission Services is dedicated to public service, and its mission is to deliver the best value for BPA customers and constituents as it acts in concert with others to ensure the Pacific Northwest has a transmission system that is prepared to integrate and transmit power from federal and non-federal generating units, provide service to BPA's customers, supply interregional interconnections, and maintain electric reliability and stability.

Transmission Services is an open access transmission provider that aligns its provision of transmission service with the Federal Energy Regulatory Commission's regulatory framework. The FERC framework is designed to prevent undue discrimination in providing access to wholesale transmission capacity. Transmission Services maintains an open access transmission tariff, and seeks to align its OATT with the FERC pro forma OATT to the maximum extent possible. The OATT process is flexible and allows for considerations from other governance structures.

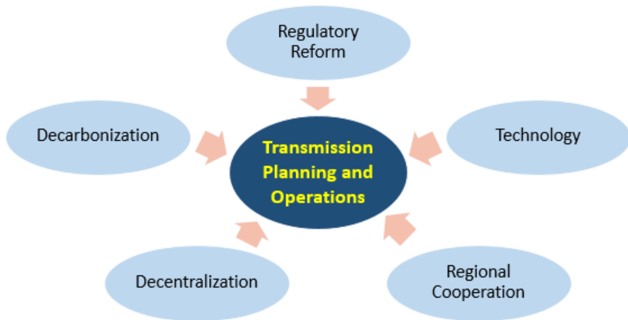
Transmission Services manages over 2,700 transmission service contracts that enable more than 30,000 transmission reservations and over 200,000 scheduling tags to be processed each month through BPA's commercial systems. Transmission's revenues are about $1.01 billion annually. Transmission Services provides transmission service to BPA Power Services customers, investor-owned utilities, independent power producers and any other business requiring the use of the Federal Columbia River Transmission System. Interested parties request transmission services and follow a well-defined process.

BPA's 2018 – 2023 strategic plan lists four agency objectives:

1. Strengthen financial health.
2. Modernize assets and system operations.
3. Provide competitive power products and services.
4. Meet transmission customer needs efficiently and responsively.

BPA's transmission objectives and strategies are based on its ability to deliver power efficiently and responsively.

Figure 8.1 – Major Trends Impacting Transmission



For 2022, Transmission Services continues to operate in a landscape of trends that started 10 to 15 years ago. The 2022 Resource Program incorporates the regional trend of new resources, such as wind – including offshore wind – and solar, and the continuing decline of coal generation, while hydro and natural gas continue to hold their share. The major trends for Transmission Services are:

- **Decarbonization:** The prevalent public policy of decarbonization from state regulators in the power and transportation industry has a variety of effects on BPA's future resource mix and load profile. The growth of variable solar and wind resources in the Northwest and California has already changed transmission operations relative to historic patterns, such as shifting the time of peak flows on some paths to be closer to sunset hours to manage the "duck curve" resulting from the ramping up of solar resources in California. BPA anticipates these trends to continue and likely become more pronounced as solar penetration continues to increase across the West. Decarbonization policies also influence the electrification of the transportation industry. The Northwest has the second largest penetration of electric vehicles in the country. BPA expects load profile changes and increased energy demand with a higher penetration of electric vehicles.

- **Decentralization:** More decentralized wind and solar generators are replacing centralized coal plants near major load centers, e.g., Centralia, Washington, and in more remote locations, e.g., Colstrip, Montana and Point of Rocks, Wyoming. Residential solar is not common in the region, but utility scale wind and solar projects are, and they tend to be located in rural areas in BPA's service territory. These individual wind and solar projects are generally smaller increments than single coal units, and there are numerous projects proposed or moving forward. The transmission grid of the future will be able to serve a growing number of these smaller generators, in addition to the larger ones in a very diverse set of locations.

- **Technology:** Technology affects every part of the power industry. The faster pace of innovation in a range of areas will affect Transmission Services in different ways.

    - **Data centers:** The dramatic growth of digital products has increased the need for data centers, and the rural Northwest is one of the preferred locations. BPA expects that trend to continue.

  - **Electrification:** Changing technologies for the end user, such as increased electrification of the transportation sector, will change the load curve. Other examples of the end-user electrification is the continuing shift to more digital technologies in lighting and increased use of batteries in consumer electronics.
  - **Smart grid:** The development of a variety of digital technologies and tools offer Transmission Services the opportunity to improve its operations, security and customer support.
  - **Solar and wind resources:** Solar and wind technologies will be the prevailing resources developed in the planning horizon. In addition, there is increased interest in developing offshore wind along the Washington and Oregon coasts.
  - **Storage:** The development of utility-scale batteries is a relatively new development in the industry. Batteries are being piloted and developed for a range of applications, but there is still a lot to learn. Costs are expected to come down over time because of volume manufacturing and chemistry advances, making their use more possible in the latter part of the decade or later. Batteries will also play a central role in the advancement of distributed energy resources, demand response, grid integration and shifting energy usage.

- **Regional cooperation:** BPA cooperates with regional partners to gain efficiencies in transmission planning and operations. BPA is active in NorthernGrid, the Western Power Pool, Western Electricity Coordinating Council workgroups and other regional planning industry organizations. In 2022, BPA joined the Western Energy Imbalance Market and is currently considering other power market initiatives.

- **Regulatory Reform:** In the last few years, federal and state regulation has been more proactive in promoting decarbonization goals. At the federal level, FERC and the Department of Energy have been active in promoting regional and inter-regional planning as well as enhancing transmission planning and generation interconnection. These regulatory reforms will have a significant impact on transmission planning in the future.

Long-Term Transmission Planning conducts production cost modeling and studies system optimization models to gauge market availability of resources, predicting future trends in resource types and location, including assumed transmission needs. Transmission Planning conducts power flow analysis to define system expansion over the planning horizon to ensure BPA's transmission system can reliably deliver resources to load and meet its transmission obligations. These analyses will inform the Resource Program in the future on market availability, transmission deliverability for future resource scenarios conducted, and transmission needs for reliable delivery of resources to loads.

8.2 Loads and Resources

8.2.1 Resources

Located on the mainstream Columbia River and on several of its major tributaries (Figure 8.2), including the Snake and Willamette rivers, the Federal Columbia River Power System, or FCRPS, comprises 31 hydroelectric projects in the Columbia River Basin and provides carbon free energy that accounts for about one-third of the electricity used in the Pacific Northwest. These federal hydro projects are operated by the Bureau of Reclamation and the U.S. Army Corps of Engineers.

Through its transmission system of more than 15,000 circuit miles of high-voltage facilities, BPA delivers and distributes the power generated from both federal and non-federal projects of all resource types such as hydro, wind, solar, etc. The revenues collected from the use of the system cover the cost of operating and maintaining the transmission facilities that comprise the Federal Columbia River Transmission System, or FCRTS.

Figure 8.2 – FCRPS Resources

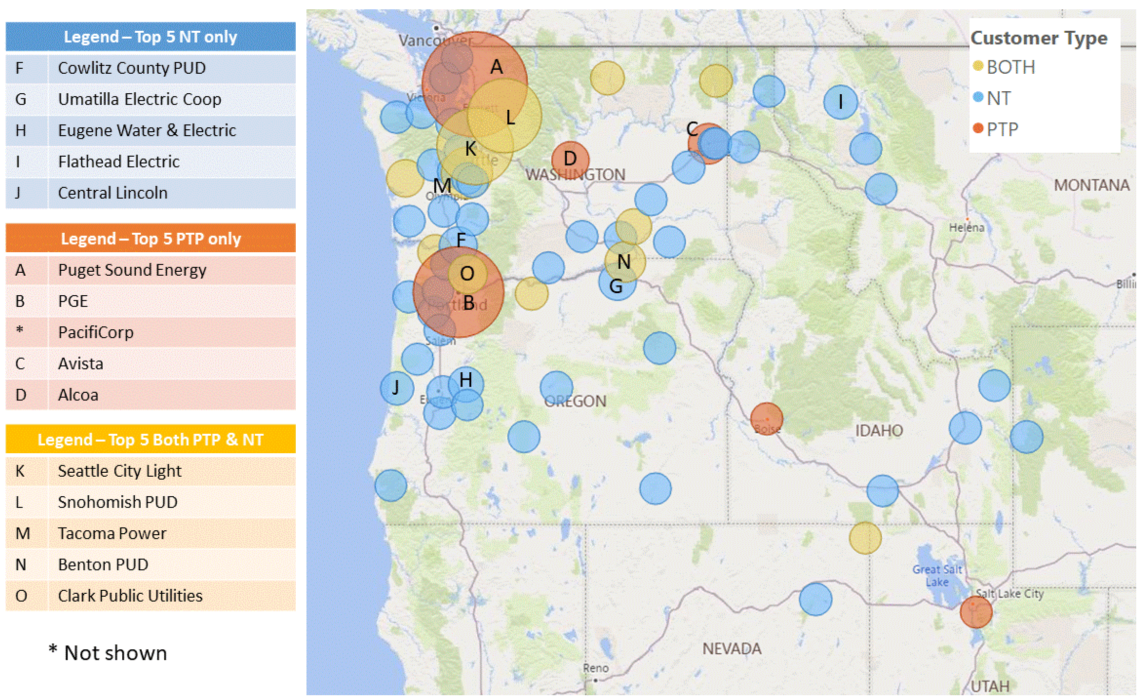
BPA delivers power from both federal hydro projects and non-federal resources, i.e. solar, thermal, wind, etc., to a wide range of customers in accordance with its OATT. Transmission service is generally divided into two products: Network Transmission, or NT, and Point-to-Point, or PTP. The traditional municipalities, public utility districts and cooperatives with load-serving priorities utilize mostly NT transmission service, while a wider variety of customers, such as investor-owned utilities, independent power producers, marketers and others utilize the more flexible and marketable PTP transmission service to access a greater mix of resources for delivery to either load or market.

8.2.2 Loads

BPA will serve 139 NT customers in the planning horizon, from 2022-2032, for a total forecast of 6,018 average megawatts in 2022 and 7,488 aMW in 2032, plus 24.4% in ten years. In 2022, 36 of these customers have demand of 5 aMW or less. A few of the NT customers will experience significant growth, while others will be mostly flat, and in some cases, negative. Among the top 10, Umatilla Electric Coop, Cowlitz PUD and Northern Wasco PUD will experience significant growth, while many municipalities remain mostly flat or even negative. The growth in the rural areas and small towns has been in large part due to data centers and industrial customers attracted to the Northwest for its low- cost power. Through the planning horizon, the forecasted NT customer peak demand will be winter peaking at 9,513 MW in 2022 and 11,311 MW in 2032.

Figure 8.3 displays projected loads for NT customers of 25 MW or greater. The load circle area is proportionally sized according to the customer load. The top five NT customers only are ranked by demand, measured in aMW, on the legend. The map includes NT and the larger PTP customers with loads of 25 aMW or more. While shown in the key, the map itself does not include PacifiCorp, delineated with an asterisk, which receives transmission service across the Northwest. The map also does not include loads smaller than 25 aMW, which aggregated to 784 aMW in 2022. Figure 8.3 also shows PTP customers, with the top five PTP customers being Puget Sound Energy, Portland General Electric, PacifiCorp, BPA Power Services and Snohomish County PUD.

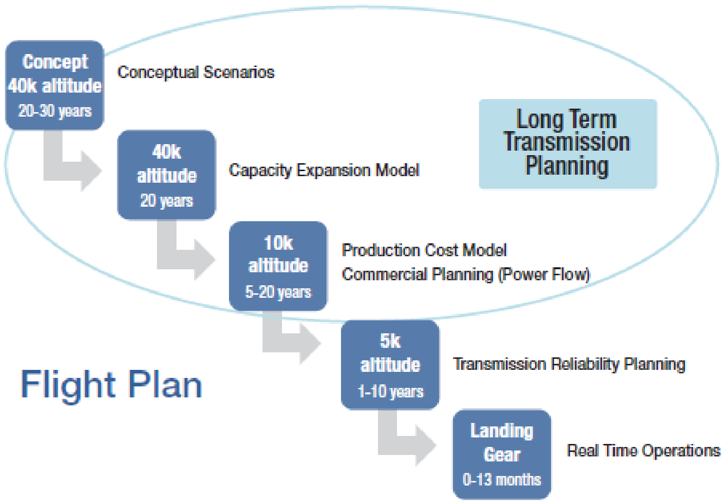
Figure 8.3 – 2022 Transmission Loads



8.3 BPA Transmission Planning

Transmission planning is done at different levels for multiple purposes. To better understand this process, Figure 8.4, Transmission Planning Flight Plan, is a graphical representation, or overview, of the various transmission planning processes within Transmission Planning and Asset Management. These processes include transmission planning from a reliability viewpoint and long-term transmission planning from a commercial planning viewpoint.

Figure 8.4 – Transmission Planning Flight Plan



A. Transmission Reliability Planning

Every year, BPA Transmission Planning conducts a comprehensive assessment of the FCRTS to determine its ability to provide reliable service over a 10-year planning horizon. Transmission Planning studies 27 load service areas and 16 paths under defined limiting system conditions in order to identify any potential performance deficiencies. The analysis is used to identify system reinforcements needed to continue to provide reliable transmission service over the planning horizon.

The system assessment allows BPA to demonstrate that existing and forecasted load and projected firm transmission service can be reliably served through, at least, the 10-year planning horizon. It also allows BPA to show that identified corrective action plans, such as system reinforcement, are adequate for reliable performance.

The main objectives of the system assessment are to demonstrate that BPA meets the mandatory North America Electric Reliability Corporation, or NERC, TPL Standard known as Transmission System Planning Performance Requirements, reliably serve loads, and fulfills obligations to reliably deliver resources to load. The NERC standard requires that BPA conduct an annual assessment to ensure that the BPA network is adequately planned to supply projected customer demand and projected firm transmission service over the expected range of forecast system demands following a wide range of probable contingency outages.

Transmission Planning evaluates the transmission system for the near-term, one to five years, and long-term, six to ten years, planning horizons to determine whether system performance meets performance requirements of the NERC TPL Standard, WECC System Performance Regional Criterion and BPA Reliability Criteria for Transmission Planning. If the system assessment identifies any potential system performance deficiencies, corrective actions, including transmission reinforcements, are developed to address the potential system deficiencies.

Load Forecast

The Transmission Planning organizations work closely with the Load Forecasting group, using a common process to identify more efficient ways of collecting and evaluating customer-provided information. This ensures that customer load information is properly modeled and analyzed. This effort is part of the Agency Integrated Planning process between Transmission Services and Power Services.

The overall system assessment starts with developing technical basecases. A basecase is a database used by the power flow software program to model the loads, topology and generation. Then, contingency outages as required by the NERC TPL Standard are studied using the basecases to assess required system performance. Assumptions are made in the system assessment basecases for load forecasts, resource forecasts and transmission service. The basecases start from WECC-approved basecases. These include initial load forecasts from BPA's Load Forecasting and Analysis group, the same initial load forecast used by Power Services for the power Needs Assessment and Resource Program, and load forecasts for other utilities represented in the basecases. If necessary, the load forecasts are then updated with the most up-to-date load forecast data available from the other utilities.

The transmission planning organizations work closely with the load forecasting group to use common processes to identify more efficient ways of collecting and evaluating customer-provided information. This ensures that customer load information is properly modeled and analyzed. This effort is part of the Agency Integrated Planning process.

Resource Forecast

Resource forecasts for the system assessment include existing and committed future resources that are expected or forecasted to operate as determined in coordination with Power Services. Specific generation patterns are assessed that are expected to create higher transmission system stress consistent with historical usage to determine the limits of the transmission system.

Existing Obligations and Committed Long-Term Firm Transmission Service

In addition to load and resource forecasts, the system assessment includes existing transmission service obligations and committed long-term firm transmission services. These transmission service obligations and commitments are identified during transmission expansion planning by BPA Long-Term Transmission Planning. System assessments conducted by Transmission Planning capture these transmission service obligations and commitments through path flows resulting from the load forecast and the generation patterns that are assessed.

Non-Wires

BPA Transmission Planning, in collaboration with the BPA Cross-Agency Non-Wires team, considers the feasibility of non-wires solutions as alternatives to or as deferrals of transmission reinforcement projects. The range of non-wires solutions that are considered include demand-side management, which includes energy efficiency and demand response, distributed energy resources such as energy storage and distributed generation, and generation re-dispatch. BPA Transmission Planning conducts a non-wires assessment to identify feasible candidates, following its annual system assessment. Non-wires alternatives to reliability projects are considered where feasible. For areas that have performance deficiencies and corrective action plans identified within the planning horizon, the potential for non-wires alternatives is identified to either correct the deficiency or defer the date when a project is required to comply with the NERC Standards. Following the system assessment, Transmission Planning summarizes the areas with the potential for non-wires projects. In collaboration with the Cross Agency

Non-Wires team, areas are prioritized, and a recommendation is made regarding which area justifies further analysis by the team.

Coordination Between Power Services and Transmission Services

Throughout the planning process, Transmission Services and Power Services work closely in a joint process called Agency Integrated Planning. The AIP process ensures a high level of coordination among the different groups to achieve efficient data collection, an analytical evaluation and optimal recommendations. Specifically, BPA coordinates between Transmission Planning, Long-Term Transmission Planning and Long-Term Power Planning in their planning activities, processes and decision-making in a way that enables the agency to meet and deliver on its statutory load-serving obligations to its regional firm power and transmission customers.

- Transmission Planning coordinates input resource assumptions for system assessment basecases with Long-Term Power Planning and Long-Term Transmission Planning. This includes ensuring that the peak period generator capacities are reasonable and properly allocated for all generating plants. Transmission Planning also collaborates on information regarding generation retirements.
- Transmission Planning coordinates long duration generator outage assumptions for basecases with federal hydro projects to include in the system assessment studies.
- System assessments and the Resource Plan start from common agency load forecasting information for BPA customers. Transmission Planning and Long-Term Power Planning coordinate with Load Forecasting and Analysis to gain a common understanding of the load forecast process, methodology and outputs.
- When the system assessment is completed, results and corrective action plans are coordinated with Power Services and Transmission Long-Term Transmission Planning to collaborate on possible integrated solutions between Transmission and Power.
- Non-wires potential, prioritization, and analysis are done in collaboration between Transmission Services and Power Services.

B. Commercial Planning

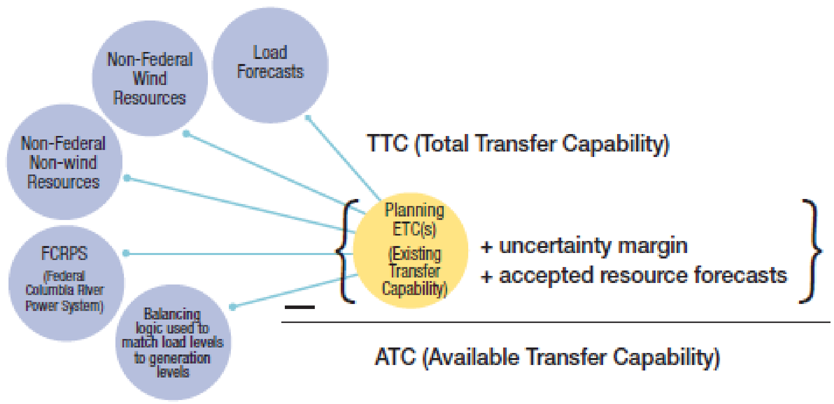
Long-Term Transmission Planning is responsible for the Transmission Service Expansion Planning for future transmission service requests, a process that starts with calculating the available transfer capacity, or ATC, for each transmission flowgate. The capacity then becomes eligible to meet the needs of BPA customers who submit transmission service requests, requesting capacity for their loads and resources. These TSRs are then combined for the cluster study's needs assessment, which serve as load scenario conditions for the cluster study. With the cluster study, the network can be analyzed for reinforcements necessary to serve the TSR needs. Customers are informed so they can make their project decisions, proceed to contract negotiations and ultimately go to construction. More on how this process works follows.

Long-Term Available Transfer Capability

On an annual cycle, BPA Long-Term Transmission Planning uses a power-flow based model to calculate Existing Transmission Commitments on BPA's monitored Network Flowgates under various system conditions and seasons. Using the calculated ETCs and the total transfer capability, the algorithm ATCFirm = TTC – ETCFirm informs the available transfer capability inventory across Network Flowgates for the long-term market. The annual LT ATC update allows BPA Transmission

Services to manage long-term firm transmission sales as well as inform the cluster study. Refer to Figure 8.5 below for a graphical representation.

Figure 8.5 – Inputs to Long-Term ATC Calculations for Network Flowgates



To calculate long-term ATC, Long-Term Transmission Planning engineers utilize five- and 10-year- out basecases for winter and summer, which originates from WECC-approved basecases. These winter and summer basecases represent a normal one-in-two non-coincidental peak load forecast. The basecases include initial load forecasts from BPA's Load Forecasting and Analysis group, the same initial load forecasts used by BPA Power Services for their Needs Assessment and Resource Program, and load forecasts for other utilities represented in the basecases. The load forecasts are then updated with the most up-to-date load forecast data available from the other utilities. A light spring basecase is derived from a summer peak basecase by reducing loads and adjusting generation patterns appropriately to reflect historical spring hydro conditions.

Resource forecasts for the FCRPS are provided by Power Services. The resource forecasts take into account forecasted FCRPS generator outages for the season. The FCRPS is modeled with three dispatches that separately stress the hydro system at the upper Columbia, lower Columbia and lower Snake projects.

Non-federal wind resources identified in PTP and NT contracts are modeled in "off" and "on" scenarios. In the "on" scenarios, PTP wind is modeled at the contract demand and capped by its nameplate, and NT wind is modeled at the designated MW level for the generator. In the "off" scenarios, PTP wind is replaced with FCRPS generation using a balancing logic method. Non-federal non-wind resources are modeled at contract demand, capped at the lower of the nameplate or historical peaks/seasonal capability.

Transmission Service Request Study and Expansion Process

Every year, Transmission Planning conducts a Transmission Service and Expansion Process, or TSEP, to analyze requests for new long-term firm transmission service. This includes a needs assessment to identify capacity deficiencies across the transmission system for future requests, and a cluster study to identify system reinforcements to provide the requested capacity. A benefit of using the TSEP is that Transmission Services can study transmission requests in aggregate, to identify "right-sized" transmission solutions to meet the demand. In addition, multiple customers then have the opportunity to participate in cost sharing of any needed transmission infrastructure, resulting in lower cost to individual customers and higher project subscription levels.

As part of the TSEP, BPA Long-Term Transmission Planning conducts a needs assessment to identify capacity needs across the transmission system in response to long-term firm TSRs, which feeds into the cluster study process. The needs assessment starts with developing a robust range of plausible scenarios that would adequately capture anticipated utilization of BPA's Network Flowgates. These scenarios consider similarly situated resources, expected resource type, and market and weather conditions in the scenario development. The needs assessment also utilizes data from production cost modeling to inform an estimated economic merit order dispatch in the scenarios, as well as new plausible scenarios of predicted congestion.

The scenario basecases used for the needs assessment are power flow models that are derived from five-year-out long-term ATC basecases for the winter, spring and summer seasons. Since the starting LT ATC basecases already include load forecasts, resource forecasts and existing transmission service commitments, the derivative scenario cases include modeling of the long-term firm transmission service requests in BPA's Long-Term Pending Queue as well as accepted NT load growth forecasts from the NT dialogue. Analysis of the set of scenario basecases determines which flowgates are deficient in capacity and the amount of capacity needed to accommodate requested future transmission service.

For those transmission paths where capacity deficiencies are identified, Transmission Planning conducts cluster studies to identify the system reinforcements needed to provide the required capacity both across the transmission paths and within local areas where associated resources are located.

Once Transmission Planning completes the cluster study and provides the results and defined transmission reinforcements, study participants decide whether to continue pursuing the requested transmission service. After the study participants have made decisions whether to support the identified transmission reinforcements, Transmission Services then initiates the next year's cluster study cycle to respond to new transmission requests submitted since the beginning of the previous study. This cyclical study process enables Transmission Services to efficiently and timely meet customer needs and satisfy its tariff obligations.

An area of recent interest for Transmission Services is the assessment of battery storage to potentially meet commercial planning needs. The exploration addresses technology improvements, increasing cost reductions in energy storage and the role of energy storage in the commercial planning space. Long-Term Transmission Planning is developing a framework to evaluate potential battery use cases, ownership models, impacts to BPA policies and an overall cost structure.

C. Long-Term Capacity Expansion

Long-Term Transmission Planning utilizes the Long-Term Capacity Expansion, or LTCE, tool to co-optimize resource and transmission capacity expansions over a long-term, 20-to-30-year horizon. The tool identifies future resource capacity and energy deficits in the various sub-regions of the Northwest and computes an optimal mix of both transmission and resource capacity additions.

The initial model is populated with at least 20 years of load, resource and transmission data at a zonal level of granularity for the Western Interconnection. Inputs in refining this base data are extracted from a variety of sources such as BPA's Transmission Planning, Load Forecasting and Analysis, and Long-Term Power Planning groups; the Northwest Power and Conservation Council; WECC; and the Northwest Power Pool.

Long-Term Transmission Planning is utilizing LTCE with the intent to evaluate several major trends in the external market landscape that affect transmission. The model has the capability to address how state carbon policies can influence the timing of transmission needs and performance in the Pacific Northwest. It can also assess how a combination of energy storage, variable energy resources and hydro perform with respect to adequacy.

D. Production Cost Model

Long-Term Transmission Planning simulates security constrained economic dispatch and unit commitment with the GridView software in order to quantify how uncertainties, such as load growth and public policy requirements, will affect transmission congestion and utilization. Scenario analysis best practices are used to identify “least regrets” transmission reinforcements.

Long-Term Transmission Planning supplements the WECC Anchor Data Set with additional data from BPA load forecasters, power planners and transmission planners. The transmission system is modeled at a nodal level of granularity with constraints approximated by path and flowgate transfer limits.

E. Intra-agency Coordination

There are several other examples of coordination between Transmission Services and Power Services for large and small projects in addition to those discussed above. One significant effort in the recent past is the Columbia River System Operations Environmental Impact Statement. For the CRSO EIS, the analytical process between the two organizations followed six steps over the course of two years. The process included linkage of changes in how and where power is generated to effects on the transmission system reliability and congestion.

Another example of coordination between Power Services and Transmission Services is the cross-agency Southeast Idaho Load Service initiative focused on how to best serve six preference customers in southeast Idaho that have long-term power and transmission contracts with BPA. This included commercial negotiations related to the Boardman – Hemingway transmission project, as well as resource acquisition and transmission service options.

There is also coordination between Transmission Services and Power Services reviewing impacts of river operations on the transmission system. This includes analyzing minimum generation levels on the lower Columbia River to maintain system reliability and to determine if other significant changes to generation patterns are expected.

Section 9: Glossary of Terms

18-Hour Capacity – Metric used for evaluating capacity surplus/deficit over the six peak load hours per day during a simulated three-day extreme weather event, such as a cold snap or heat wave, and assuming median water conditions.
Available transfer capacity – Also "available transfer capability." Measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.
Balancing authority – Synonym for load control area agency. The responsible entity that schedules generation on transmission paths ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time.
Balancing authority area – The collection of generation, transmission and loads within the metered boundaries of the balancing authority. The balancing authority maintains load-resource balance within this area.
Balancing reserves – Incremental and decremental generation flexibility or demand response that is connected to BPA's Automatic Generation Control system and is capable of responding to signals requesting Regulation Service and Within-hour Following Service in proportion to the AGC signal requirements.
Behind-the-meter generation – Energy generated on-site and on the consumer side of the meter facility, such as residential solar.
Canadian Entitlement – The Canadian Entitlement is one-half of a treaty formula that measures the increase in usable energy and dependable capacity for an imaginary 1960-level hydrothermal power system with procedures designed to provide acceptable cost/benefits during the life of the treaty.
Capacity – Capacity is defined and measured in various ways. BPA measures the capacity of its system by determining its maximum output in its 18-hour capacity studies, which represent the most stressful type of event BPA's power system could expect to experience approximately once in every 10 years.
Conservation Potential Assessment – Study conducted to assess the amount and costs of energy efficiency measures available from BPA's forecasted customer loads over the planning horizon.
Critical water – The second-lowest historical streamflows on record used to model the amount of power the regional hydropower system could produce, given today's generating facilities and constraints.
Cut plane – Group of transmission lines.
Decarbonization – Reducing the carbon content of all transformed energies such as electricity, heat, liquids and gases. In the power sector, this means replacing coal, as well as gas and oil, with renewable energy.
Decentralization – Energy generated off the main grid and produced near to where it will be used, rather than at a large plant elsewhere and sent through the grid.
Demand response – Programs intended to reduce the use of electricity during times of peak demand.
Demand-side resources – Load management programs, such as energy efficiency, implemented by utilities. These resources can also include demand response, load shifting measures, and Behind-the-meter generation and storage.
Distributed energy resources – Systems such as small-scale power generation or storage technologies – typically in the range of 1-10,000 kilowatts – used to provide an alternative to or an enhancement of the traditional electric power system.
Efficient frontier – Result from the Resource Program analysis that produces the least-cost combination of available resources that meets the given constrains. It also identifies various other combinations of resources that minimize portfolio variance for a given cost point.

Energy – The amount of electricity demanded, produced or required, over a specific period of time, sometimes measured in annual average megawatts, aMW, or in megawatt hours, MWh.
Energy efficiency – Using less energy to perform the same function or service.
Federal Energy Regulatory Commission (FERC) – An independent government agency delegated by Congress with the authority to regulate the energy infrastructure of the United States, including the transmission of electricity.
Flowgate – 1) Individual or group of transmission facilities, i.e., transmission lines, transformers, known or anticipated to be limiting elements in providing transmission service; or 2) designated point(s) on the transmission system through which the Interchange Distribution Calculator calculates the power flow from interchange transactions.
Heavy load hours – Times of highest electricity usage; for BPA, heavy load hours are hours ending at 7 a.m. to 10 p.m., Monday through Saturday, excluding North American Electric Reliability Corporation holidays.
Hub – Combination of the electrical grid and other networks, such as natural gas pipelines, for the production, conversion, storage and consumption of different energy generators.
Independent power producer – A non-utility producer of electricity that operates one or more generation plants under the 1978 Public Utility Regulatory Policies Act, PURPA. Many independent power producers are co-generators who produce power for their own use and sell the extra power to their local utilities.
Integrated Resource Plan – A long-term resource planning process conducted to help ensure a utility meets its expected future obligations at low cost and with minimum practical risk.
Intertie – A system of transmission lines permitting a flow of energy between major power systems. The BPA transmission grid has interties to British Columbia, California and eastern Montana.
Investor-owned utility – A privately owned utility organized under state law as a corporation to provide electric power service and earn a profit for its stockholders; a private utility.
Light load hours – Generally, times of low electricity usage; for BPA, light load hours are hours ending 11 p.m. to 6 a.m., Monday through Saturday, all day Sunday and holidays as designated in the North American Electric Reliability Corporation Standards.
Load – The amount of electric energy delivered or required at any specified point or points on a system.
Market depth limit – Result of a study used to determine how much energy BPA could reliably purchase from the wholesale market.
Market transformation savings – Associated with the Northwest Energy Efficiency Alliance's programs and initiatives that focus on long-term market change and push the region toward more efficient technologies.
Momentum savings – BPA tracks and reports momentum savings for select markets. Momentum savings are defined as all the energy efficiency occurring above the Northwest Power and Conservation Council's plan baseline that are not directly reported by utilities and not part of the Northwest Energy Efficiency Alliance's market transformation savings.
Network transmission – Transmission contract or service described in a transmission provider's Open Access Transmission Tariff, OATT.
North American Electric Reliability Corporation (NERC) – A not-for-profit international regulatory authority appointed by the Federal Energy Regulatory Commission whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.
Northwest Energy Efficiency Alliance (NEAA) – A group of 140 Northwest utilities and energy efficiency organizations that fund activities and programs dedicated to accelerating energy efficiency in the region.
Open Access Transmission Tariff – Tariff for use of high-voltage transmission lines required by FERC under its Order 888. Designed to facilitate open, nondiscriminatory access to all transmission facilities by all power providers; terms and conditions by which BPA provides nondiscriminatory transmission service

that is similar to the Federal Energy Regulatory Commission's pro forma tariff mandated for FERC jurisdictional utilities.
Outage – In a power system, an either scheduled or unexpected period during which the transmission of power stops or a particular power-producing facility ceases to provide generation.
P10 – The 10^{th} percentile of a distribution.
P10 heavy load hour – Criteria that evaluates the 10th percentile, or P10, surplus/deficit over heavy load hours by month, given variability in hydropower generation, load obligations and Columbia Generating Station output amounts.
P10 Super-Peak – Criteria that evaluates the 10th percentile, or P10, surplus/deficit over the six peak load hours per weekday by month, given variability in hydropower generation, load obligations and Columbia Generating Station output.
Peak load – The highest amount of one-hour load on the entire system in a stated period of time. It may be the maximum load at a given instant in the stated period or the maximum average load within a designated interval of the stated period of time.
Peak runoff – The period of time during which the maximum volume of precipitation, snowmelt or irrigation water that runs off the land into streams or other surface water within a watershed or basin. BPA forecasts the amount of water expected to enter the Federal Columbia River Power System based on winter snowpack measurements and historical volumes.
Point-to-point transmission – Reservation and/or transmission of energy on either a firm basis and/or a non-firm basis from point(s) of receipt to point(s) of delivery, including any ancillary services provided by the transmission provider in conjunction with such service.
Ramp rates – 1) The amount of conservation or demand response that a program can acquire annually; 2) The rate at which the power output of a generator or generating project can be increased or decreased.
Redispatch – Management of generation patterns to overcome cut plane or outage problems.
Resource portfolio/stack – A set of resources, such as nuclear, natural gas, wind, solar and/or hydropower, used to provide power products. Demand side resources such as conservation, storage, rooftop PV, and demand response can also be in a resource portfolio.
Spill – Water that goes over the spillway of a dam rather than through its turbines, meaning it is not used to generate electricity.
Supply-side – Generating resources or activities on the utility's side of the customer's meter used to supply electric power products or services to customers, rather than meeting load through energy-efficiency/conservation measures or on-site generation on the customer's side of the meter.
Western Interconnection – Synchronously operated interconnected electric transmission systems located in the Western United States, Baja California, Mexico, and Alberta and British Columbia, Canada.
Western Electricity Coordinating Council (WECC) – An independent, non-profit organization delegated by NERC and FERC to promote the reliability of the power system in the geographic area known as the Western Interconnection.

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