BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-121:
2025 Bonneville "White Book"

BONNEVILLE POWER ADMINISTRATION

2025 Pacific Northwest Loads and Resources Study

May 2025





2025 PACIFIC NORTHWEST LOADS AND RESOURCES STUDY

The White Book

BONNEVILLE POWER ADMINISTRATION
May 2025

Cover Picture:
Source: BPA Photo Archive https://river.bpa.gov

The McNary Dam is one of the four Federal projects located on the Lower Columbia River in the Pacific Northwest; it is part of the Columbia River Basin hydro projects. It serves a variety of purposes such as irrigation, navigation, recreation, and hydropower.

McNary Dam is a run-of-river type of Dam located roughly 290 miles upriver from the mouth of the Columbia River connecting Umatilla County, Oregon with Benton County, Washington. It has a powerhouse, navigation lock, as well as fish ladders and plays a major role in the transportation of commodities in the Columbia-Snake Inland Waterway. It is operated by the U.S. Army Corps of Engineers.

For more information on The McNary Dam, please visit: Walla Walla District - McNary Lock and Dam

https://www.nww.usace.army.mil/Locations/District-Locks-and-Dams/McNary-Lock-and-Dam/

ACKNOWLEDGMENTS

Preparation of the annual Pacific Northwest loads and resources study is a complex, multidisciplinary effort. BPA wishes to acknowledge the team—BPA staff and others—whose diligence and dedication result in a reliable, high quality document.

Bonneville Power Administration

Generation Asset Management:

Long Term Power Planning Group
Regional Coordination Group
Operational Planning Group

Customer Support Services:

Load Forecasting and Analysis Group

Bulk Marketing and Transmission Services:

Long Term Sales and Purchasing Group

NW Requirements Marketing:

Office of General Counsel

Pacific Northwest Utilities Conference Committee

Northwest Power & Conservation Council

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Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

May 16, 2025

In reply refer to: PGPR-5

Dear Interested Parties:

The Pacific Northwest Loads and Resources Study, commonly called "The White Book", is the Bonneville Power Administration's (BPA) annual publication of the Federal system and the Pacific Northwest (PNW) region's loads and resources for the upcoming ten-year period.

The White Book is used by BPA as a planning tool, as an information source for customers, as a published source of loads and resources information for regional interests, and as a data source for the Columbia River Treaty studies. The White Book is not used to guide day-to-day operations of the Federal Columbia River Power System (FCRPS) or to determine BPA revenues or rates.

This 2025 White Book presents the Federal system and the region's load obligations, contracts, and resources as of December 2024 for operating years (OY) 2026 through 2035. The 2025 White Book includes the following studies:

- Federal System Analysis—forecast of Federal system firm loads and resources based on expected load obligations and different levels of generating resources that vary by water conditions. The results are summarized below:
  - Annual Energy Surplus/Deficits: Under firm conditions; the Federal system is projected to have annual energy deficits across the study period, ranging from deficits of 426 aMW to 1012 aMW. Overall, these annual energy deficit projections are more than those projected in the 2024 White Book. Under median water conditions, the Federal system is projected to have annual energy surpluses throughout the study period.
- PNW Regional Analysis—forecast of regional firm loads and resources, based on expected retail loads and different levels of generating resources that vary by water conditions. The decommissioning of existing resources, the availability of uncommitted PNW Independent Power Producer (IPP) generation, and new resource additions are key variables in the results of this analysis. The results are summarized below:
  - Annual Energy Surplus/Deficits: Under firm water conditions, the PNW region is projected to have an annual energy surplus as large as 960 aMW in OY2026, then sharply decreasing to a deficit of 3,026 aMW by OY2034. This result was mainly driven by the increasing PNW Retail Loads. Overall, the annual energy surplus/deficit position projections are more surplus than forecasts from the 2024 White Book until the outyears of the study period. Under median water conditions, the PNW region would begin to see energy deficits in the out years.

In February of 2025, BPA published our 2024 Resource Program designed to evaluate long-term power resources acquisition strategies. Many factors contribute to the uncertainty of the longer-term resources outlook for the region, such as resource retirements and development, resource adequacy and the efforts surrounding it, and other Federal and State policy mandates. As with resources, there is also much uncertainty with loads including the potential for electrification and data centers coming online. The 2024 Resource Program publication and the 2025 White Book are available on BPA's website: https://www.bpa.gov/energy-and-services/power/resource-planning or from BPA's Visitor Center, which you can reach toll-free at 800-622-4520 (or 503-230-4636). Details regarding regional loads, contracts, and generating resources are available upon request. The available report list can be found in the Appendix.

Please send questions and/or comments to whitebook@bpa.gov.

Sincerely,

MICHELLE CATHCART

Digitally signed by MICHELLE CATHCART
Date: 2025.05.27 13:17:25 -07'00'

Michelle Cathcart
Vice President| General Asset Management
Bonneville Power Administration
Enclosure

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SECTION 1: SUMMARY

Planning Context

The Pacific Northwest Loads and Resources Study, commonly referred to as the White Book, is a planning document produced by the Bonneville Power Administration (Bonneville) that presents its projection of load and resource conditions for the upcoming 10-year period from operating year (OY[1]) 2026 to 2035 (referred to in this document as "the study period"). The White Book includes analysis of Bonneville's forecasts of expected power obligations and resource generation for both the Federal system and the Pacific Northwest[2] (PNW) region. Information contained in the White Book is used for: 1) long-term planning studies for Bonneville; 2) planning studies for the Columbia River Treaty (Treaty); and 3) as a published record of information and data for customers and other regional planning entities. The White Book is not used to guide day-to-day operations of the Federal Columbia River Power System (FCRPS).

Bonneville's White Book traditionally focuses on long-term deterministic power planning for the Federal system and the PNW region. The load and resource balance are calculated by comparing expected loads and contract obligations to forecast resource generation and contract purchases under the Federal system. In the same manner, Bonneville's PNW regional analysis calculates the PNW regional load and resource balance by comparing expected regional retail loads and contract obligations to forecasted regional resource generation and contract purchases. Hydropower resources for the Federal system and PNW regional include variability by incorporating a variety of generation forecasts, associated with streamflow from the most recent 30-historical water conditions of the 2020 Modified Flows. These deterministic analyses are modeled by OY to be consistent with regional coordination of the Treaty. Analytical results are presented in annual and monthly energy, expressed in average megawatts (aMW). The Federal System Analysis is presented in Section 2, and the Pacific Northwest Regional Analysis in Section 3.

Bonneville, like the rest of the electric power industry, continues to explore ways to comprehensively assess the ability of the power system to meet long-term load obligations. Periodically, Bonneville incorporates additional studies and data into its planning that look at different analytical methods and evaluate different scenarios. This year's White Book does not incorporate any additional studies.

The total retail load, contracts, and generation forecasts used in this study were updated as of December 31, 2024. The 2025 White Book supersedes the 2024 White Book and is published as a single summary document.

A list of technical reports can be located at the end of this summary document in the Appendix, individual reports are available upon request only. Request for these reports can be made by emailing WhiteBook@bpa.gov.

[1] Operating Year (OY) is the time frame August 1 through July 31. For example, OY 2026 is August 1, 2025 through July 31, 2026.

[2] As defined in the Northwest Power Act

Load Obligations

The load obligations for the Federal system and PNW region contain multiple components in this study, forecasts are categorized as: 1) Total Retail Loads (TRL), defined as each individual utility's total retail electric power consumption on its system, including electrical system losses; and 2) contract obligations, which include reported PNW utility long-term contract sales within the PNW region as Intra-Regional Transfers (Out) and outside the PNW region as Exports. Contract obligations also include Federal system power sales delivered to Federal agencies, public bodies, cooperatives, and tribal utilities as preference customers described under section 5 of the Northwest Electric Power Planning and Conservation Act (NW Power Act), 16 U.S.C. 839 et seq., (December 5, 1980).

Forecasts of the regional TRL and Federal system load obligations are produced by Bonneville's Agency Load Forecasting (ALF) system. ALF forecasts are completed for individual PNW entities under one of two approaches, the largest share of load forecasts is now based on statistically adjusted end-use models while other forecasts are based on time-series-based regressions that follow the fundamental assumptions of historical retail electricity consumption patterns continuing. The statistically adjusted end-use models include calculated indexes for heating and cooling equipment, and other components. ALF forecasts also assume normal weather conditions, using normalized temperatures based on recent history to incorporate evolving climate trends. Obligations associated with Bonneville's Preference Power Sales Contracts are forecasted to continue as currently elected through the study period, contract obligations not associated with Bonneville's Preference Power Sales Contracts follow individual contract terms through the life of the contract and are not assumed to be renewed. All Federal system load and contract obligations are assumed to be firm and served by Bonneville regardless of weather, water, or economic conditions.

Resource Types

Regional resources consist of physical generating facilities (currently on-line and/or under construction) and contract purchases that are used to serve retail loads. PNW resources, with Federal systems included, are predominantly hydro based; therefore, generation levels can vary greatly both from month-to-month and from year-to-year. This analysis classifies resources as: 1) Hydro resources, which include regulated, independent, and small hydro projects; 2) Non-hydro renewable resources, which include wind, solar, and other renewable projects; 3) Thermal resources, which include nuclear, coal, natural gas, petroleum, biofuel and cogeneration projects; 4) Contract purchases, which include reported PNW utility long-term contract purchases from within the PNW regional as Intra-Regional Transfer (In) and from outside the PNW regional as Imports. Generation forecasts for these resources are provided by Bonneville models or from the project owners, and those are described in detail in the following sections.

Hydro Resources

- Regulated Hydro – Regulated hydro projects mainly consist of PNW Columbia River Basin hydro power projects for which the operation and generating capability is hydraulically linked. Bonneville forecasts the coordinated energy and capacity production from these hydro power projects using its Hydro-system Simulator (HYDSIM) model. The HYDSIM model considers

individual project operating characteristics and conditions to determine energy production expected on a project-to-project basis. Generation forecasts for these projects incorporate the month-to-month power and non-power requirements under each of the 30 historical streamflow conditions of record, 1989 through 2018. The HYDSIM model is described further in the Hydro Resource Modeling section.

- Independent Hydro - Independent hydro projects include those hydro projects whose generation output typically varies by water condition and are not operated or hydraulically linked to part of the Columbia River Basin. Independent hydro generation forecasts can vary month-to-month for energy and capacity and are developed and provided by individual project owners/ operators for the same 30-historical water conditions as the Regulated Hydro projects (1989 through 2018).
- Small Hydro – Small hydro project generation forecasts are either provided by individual project owners or are based on historical actual generation. These generation forecasts vary month-to-month; however, they are not assumed to be dependent on water conditions.

Non-Hydro Resources

- Wind – Firm wind generation incorporates the statistical modeling of wind generation based on historical weather data and actual generation from currently operating PNW wind projects. The single operating year with the lowest total PNW wind generation is selected as firm wind year. The firm wind year generation performance determines each project's energy forecast. The Federal system and PNW regional capacity analysis assume zero capacity contribution from wind resources.
- Solar – Solar projects are utility scale solar facilities that are metered and send generation to the grid; this does not include any behind the meter resources. Generation forecasts are either provided by individual project owners or are based on historical actual generation. The Federal system and PNW regional capacity analyses assume zero capacity contribution from solar resources.
- Other Renewable – Other renewable resources include all other projects identified as renewable, including geothermal and biomass/biogas waste projects. Generation forecasts for these resources are based on energy and capacity forecasts submitted by individual project owners.

Thermal Resources

- Thermal resources include nuclear, coal, natural gas, petroleum, biofuel (not identified as renewable), and cogeneration projects. Generation forecasts for these projects are based on energy and capacity capabilities submitted by project owners. These forecasts typically vary month-to-month, and total plant generation is reduced to account for scheduled maintenance. Forecasts are adjusted to show actual operational capabilities and expectations, and do not reflect economic dispatch.

Contract Purchases/ Imports

- Contract purchases include signed Federal system purchases and regional contract purchases with power delivered to PNW entities reported by utilities publicly and in data submittals.

These purchases are treated as resources in both the Federal system and PNW regional analyses. Purchases between entities within the PNW are called Intra-regional Transfer (In) and purchases from entities outside the PNW are categorized as Imports. Except for contracts associated with the Treaty, all existing Federal system and regional contract purchases follow individual contract terms throughout the life of the contract and are not assumed to be renewed. Treaty power deliveries are assumed to be in place through the study period.

Adjustment to Resources

The White Book assumes that resource generation and contract purchases are reliably delivered to load centers. To take this assumption into account, this study adjusts generation forecasts for 1) Operating and Balancing Reserves, held to meet reliability standards; and 2) Transmission losses, associated with power deliveries. These adjustments are considered as reductions to both energy and capacity and are described below:

- Operating and Balancing Reserves: Operating reserves consist of both spinning and non-spinning contingency reserves that respond to the unforeseen loss of a resource, which are calculated by summing three percent of forecast load and three percent of forecast generation. Balancing reserves consist of regulating, load following, and imbalance reserves that are dedicated to maintaining within-hour load and resource balance. Details in modeling of reserves are described in the Hydro Resource Modeling section. Reserve forecasts included in this White book are modeled consistent with those used in Bonneville's BP-26 Rate Case process.
- Transmission Losses: During the transmission of power to load centers some of the electrical energy is lost, typically in the form of heat, which is categorized as transmission losses. Transmission loss factors are calculated monthly and vary by seasonal generation, e.g. summer months versus winter months. Transmission Loss factors are applied to the sum of all generation and contract purchase forecasts. The monthly transmission loss factor has several components that combine to give the estimate of losses associated with Federal system generation: 1) step-up transformers from generation to the high-voltage transmission network; 2) high-voltage network transmission; 3) transfers to Federal loads over non-Federal transmission systems; and 4) step-down transformers from high-voltage transmission to low-voltage delivery. The Federal system transmission loss factors used in this White Book are consistent with those used in Bonneville's BP-26 Rate Case process:
    - Energy: 2.83 percent from September through May, and 3.04 percent from June through August.
    - Capacity: 2.88 percent from September through May, and 3.09 percent from June through August.
- Wheeling Loss (Financial Settlements): During the transmission of power from physical resource to load centers some of the electrical energy is lost, typically in the form of heat, which is categorized as transmission losses. Wheeling losses are those losses incurred by transmission customers who have elected to settle those losses financially. The calculation of wheeling losses is based on the losses on the 'high-voltage network transmission' system.

Hydro Resource Modeling

The HYDSIM hydro regulation model forecasts the energy production from the regulated hydroelectric power projects in the PNW. This includes the 14 federal hydroelectric projects that make up the Columbia River Federal system, and other major hydro projects in the PNW. Project level generation forecasts are produced in a continuous study for each month of the 30 year-historical streamflow record[3]: October 1989 through September 2018. Energy production is maximized by coordinating hydro operations while meeting power and non-power requirements. HYDSIM produces results for 14 periods: ten complete months plus two periods each for April and August. April and August are divided, first half -second half, due to natural streamflow and significant operational changes happening during these two months. Consequently, generations can differ significantly between the beginning and end of these months. For simplicity, the 14-period results are referred to as "monthly" values in this report.

The HYDSIM studies encompass both power and non-power operating requirements. Each hydro study specifies non-power hydroelectric project operations for fish, such as seasonal flow objectives, minimum flow levels for fish, spill for juvenile fish passage, reservoir target elevations and drawdown limitations, and turbine operation requirements. The operations modeled include the following as outlined in the U.S. Army Corps of Engineers Pacific Northwest Coordination Agreement (PNCA) data submittals:

- National Marine Fisheries Services 2008 Willamette Biological Opinion (BiOp) (July 11, 2008)
- 2020 Columbia River System Operations Environmental Impact Statement (CRSO EIS), (Sept. 28, 2020)
- 2020 NOAA Fisheries Federal Columbia River Power System Biological Opinion (2020 NMFS BiOp) (July 24, 2020)
- 2020 U.S. Fish and Wildlife Service Biological Opinion (November 12, 2019)
- 2023 MOU Appendix B 10-yr spill agreement (December 14, 2023)

Although the PNCA expired on September 15, 2024, PNCA project owners provided physical plant data as well as power and non-power constraints in a final data submittal to the Western Power Pool (WPP) in February 2024. Bonneville incorporates this data into HYDSIM to simulate the coordinated operation of the PNW hydro system. As with previous White Books, these assumptions were included through the 10-year study horizon. The 2025 White Book includes studies that reflect the expiration of the PNCA.

The construction of the three storage projects in Canada - Mica, Arrow, and Duncan - under the Treaty between the United States and Canada enhanced the volume of storage in the Columbia River Basin. These projects provide downstream power benefits by increasing the firm power generating capability of U.S. hydro projects. The Treaty calls for an Assured Operating Plan (AOP) to be completed six years prior to each operating year and allows a Detailed Operating Plan (DOP) to be

[3] 2020 Modified Flows

completed, if agreed upon, in the year prior to the operating year. The Canadian project operations simulated in HYDSIM are based on the best available information from the Treaty planning and coordination process. Canadian operations included in this White Book are based on the official 2025 AOP studies, with additional modifications that reflect updates used in the official 2025 DOP studies.

For the past several years, the United States and Canada have been in negotiations to modernize the Treaty. In July 2024, the United States and Canada reached a non-binding agreement on core issues to be reflected in a modernized Treaty and subsequently began the process of negotiating and drafting modernized Treaty text. During the pendency of these negotiations, the Countries agreed to implement a set of interim measures concerning the following aspects of Columbia River coordination:

- Beginning August 1, 2024, the Canadian Entitlement was reduced from 1141 Megawatts (MW) of hydropower generation capacity and 454 average MW (aMW) of energy to 660 MW of capacity and 305 aMW of energy. The Canadian Entitlement will stay at this reduced level until OY 2031, when it will be further decreased and then stabilized at 550 MW of capacity and 225 aMW of energy from OY 2034 through OY 2044.
- Effective November 1, 2024, Canada's Powerex assumed and started paying for 1,120 megawatts of transmission rights previously held by Bonneville to deliver the Canadian Entitlement.
- From September 2024 through 2027, Canada will provide 3.6 million acre-feet of water storage at Arrow Lakes reservoir for flood risk management for the United States, upon election and compensation by the Corps on behalf of the United States.
- Canada will provide up to 1.0 million acre-feet of flow augmentation to aid in salmon migration in the 2024-2025 operating year.

Bonneville along with the Corps is continuing to carry out and implement operational and other obligations pursuant to the current Treaty and associated agreements. The Canadian Entitlement energy amounts included in this White Book for OY 2026 through OY 2035 are based on the amounts identified above.

Balancing reserves, both incremental and decremental, reduce the ability to shape the Federal system generation. Incremental reserves are modeled by reducing the generation capability of projects.

Firm planning

Bonneville bases its resource planning on firm expected generation to ensure sufficient generation to meet obligation loads. Firm conditions are defined as when the PNW hydro system would be the most limited, due to a combination of operational constraints and low water conditions. For the Federal System this is established by considering the historical streamflow record, power and non-power operation constraints and the planned operation of non-hydro resources, combined with the

system load requirements. For operational purposes, Bonneville considers firm condition to be the tenth percentile (P10) of the monthly Tier One System Firm Critical Output (T1SFCO) system results. The percentile approach eliminates the anomalies observed in any single water year, e.g. 1937; it also aligns with metrics used in Bonneville's Resource Program[4].

Variability of Hydro Generation

The generating capacity of the Federal system and PNW regional hydro projects depends on several factors: 1) the amount of water flowing through the facilities, 2) the physical capacity of the facilities, 3) any flow or operating requirements, including those pursuant to biological opinions, court orders or applicable agreements, and 4) other operational limitations. Water conditions cause hydro generation to vary greatly year-to-year depending on weather factors such as precipitation, snowpack, and temperature. Project-level generation forecasts for regulated hydro resources are produced using HYDSIM for each of the 30 historical streamflow conditions of record, which are based on the period from 1989 through 2018. Additionally, Federal independent hydro project generation was updated by the Army Corps of Engineers, the Bureau of Reclamation, and other project owners incorporating the 2020 modified flows and up to date project operations.

This White Book study uses three generation scenarios to demonstrate the magnitude of hydro generation variability:

- Firm water: tenth percentile (P10) of system generation by month, it represents the firm water condition for energy and capacity of the hydro system.
- Median water: 50th percentile (P50) of system generation by month, it represents the exact middle value of generation distribution for energy and capacity of the hydro system.
- High water: 90th percentile (P90) of system generation by month, this represents the high generation scenario of the energy and capacity of the hydro system.

Hydro Capacity Modeling

Bonneville uses the RiverWare[5] model to forecast usable hydro capacity for long-term planning purposes. RiverWare incorporates the monthly historical 30 water year reservoir storage and flows from HYDSIM to simulate the relationship of hydro energy to hydro peaking capability for Federal system regulated hydro resources. For each month, RiverWare forecasts hourly Federal system hydro generation by maximizing generation while meeting non-power requirements. The forecasts consider scheduled hydro maintenance and reserves.

[4] Bonneville Power Administration Resource Planning

[5] RiverWare is a river system modeling tool developed by the University of Colorado Boulder College of Engineering and Applied Science, more specifically by the Center for Advanced Decision Support for Water and Environmental Systems (CADSWES). RiverWare | Center for Advanced Decision Support for Water and Environmental Systems | University of Colorado Boulder

Notable Updates

- The 2025 White Book includes updated forecasts of Federal system power sales contracts (PSC) obligations, PNW regional Total Retail Loads (TRL), contract purchases, and generation as of December 1, 2024.

Hydro capabilities in this study also reflect the updated Resilient Columbia Basin Agreement (RCBA, also known as the 12/14 agreement), published on 12/15/2023. Key items include:

- Spilling most projects in the spring to 125% Total Dissolved Gas (TDG) gas cap in the spring 24/7.
- John Day spills 40% of outflow for 16 hours during the day, and 125% TDG for 8 hours at night.
- Little Goose spill includes 8 hours of spill totaling 30% of outflow allowing for adult passage and 125% TDG for the remaining 16 hours, except 30% of outflow spill early in season does not begin until the sooner Apr 24th or adult criteria are met.
- Late summer spill transitions on August 1st instead of August 15th.
- Steelhead spill Sept-Nov 15th is everyday instead of every other day (4 hours per day via 1 Spillway Weir).
- Steelhead and early run juvenile spills are 24/7 beginning March 21st until the start of juvenile spill.

Sources of Uncertainty

Forecasts presented in this document represent the best information currently available under the defined metrics for loads and resources. However, all forecasts are affected by uncertainty in economic conditions, weather, environmental and governmental policies, and a variety of other factors that could significantly affect the magnitude, duration, and timing of projected surpluses and/or deficits. Uncertainties include:

- Changes to hydro system operations in response to Endangered Species Act requirements or other environmental considerations,
- Changes to hydro system operations in response to court actions and/or operational agreements,
- Natural variations in weather affecting electrical power demand and streamflow runoff that result in hydroelectric power generation changes,
- Potential new large individual retail load and/or other changes to major industrial operations,
- Potential service to new load such as new customers or the Department of Energy's Richland vitrification plant operations,
- Potential future policy requirements at local, state, and federal levels regarding the amount and type of renewable resources, conservation standards, electric vehicle saturation, and/or carbon emissions,
- Fuel cost and availability, which may be affected by environmental factors or competing uses for industry, transportation, and import/export markets,
- Changes to operating limits on existing and future thermal resources,

- Changes to retirement dates associated with resources,
- Failures of resources to operate at anticipated times and/or output levels,
- Changes to Treaty operations after the time the study was run,
- PNW entities' ability to purchase power from new and existing uncommitted regional resources to serve retail load,
- PNW entities' ability to purchase and transmit power from extra-regional import/export markets,
- Future obligations related to Provider of Choice elections.

The potential impacts of these and other sources of uncertainty are not quantified in this study.

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SECTION 2: FEDERAL SYSTEM ANALYSIS

The Federal System Analysis provides a deterministic forecast of the federal system loads and resources over a 10-year period from OY2026 through 2035. This analysis incorporates forecasts of the Federal system's firm requirement PSC obligations, contract sales and purchases, and resource generations. This section presents firm Federal system load and resource forecasts for energy. Additional detailed components of the Federal system study are available only upon request, a list of available reports can be found in the Appendix.

Load Obligations

Bonneville's ALF system is used to forecast Federal system load obligations, as described previously in Section 1: Summary – Load Obligations. Types of Federal system load obligations include: 1) Federal reserve power obligations to the U.S. Bureau of Reclamation (USBR), 2) Bonneville's Regional Dialogue (RD) PSC obligations to public, cooperative, and tribal utilities, and Federal agency customers, 3) contract obligations to investor-owned utilities (IOUs), 4) contract obligations to Direct Service Industry (DSI) customers, and finally 5) other Bonneville contract obligations including contract sales to entities within the PNW region (Intra-Regional Transfers (OUT)) and to those outside the PNW region (Exports). These load obligations are all considered firm power deliveries and are assumed to be served by the Federal system regardless of weather conditions, water supply, or economic environments. Bonneville's forecasts of these obligations are categorized in the following sections.

USBR obligations

USBR must meet statutory directives to provide reserve power to irrigation district facilities associated with USBR projects. Individual USBR project authorizations provide for irrigation districts to receive reserve power from specific FCRPS projects. The remaining power from USBR projects are marketed by Bonneville in the PNW.

RD Contract High Water Mark (CHWM) PSC obligations to Public & Federal agency customers

In December of 2008, Bonneville executed RD PSCs with public, cooperative, and tribal utilities, as well as federal agency customers. Bonneville is obligated to provide firm power deliveries from October 1, 2011, through September 30, 2028. Customers were offered three types of products: Load Following, Slice/Block, and Block. A total of 134 customers signed the RD contracts, and in this current period 124 are Load Following customers, 7 are Slice/Block, and three are Block.

Under the RD PSCs, customers made periodic elections of how to serve their Above Rate Period High Water Mark (A-RHWM)[6] load by 1) adding new non-Federal resources; 2) acquiring power from non-

[6] "Through the contracts and rate methodology, each public utility will get a High Water Mark (HWM) that defines its right to buy an amount of power at BPA's lowest cost-based Tier 1 rate. Power above the HWM must be purchased from either

Federal resources; and/or 3) requesting Bonneville to supply additional power (as a Tier 2 load service). The final customer election was made in October 2024 and set through fiscal year (FY) 2028, and this study assumes these along with the current contract elections continue throughout the study period. Based on this assumption, Federal system RD PSC obligation forecasts include elected and forecasted A-RHWM (Tier 2) load for the study period. Table 2-1 presents the A-RHWM load included in Bonneville's obligations by FY.

Table 2-1 Above Rate-High-Water-Mark Obligations (BP26 Rate Case)

FY	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy aMW	534	579	619	696	692	734	768	806	836	862

IOU Load Service under Regional Dialogue (RD) PSCs

There are six IOUs in the PNW region, and they are: Avista Corporation, Idaho Power Company, Northwestern Energy Division of Northwestern Corporation, PacifiCorp, Portland General Electric Company, and Puget Sound Energy, Inc. Although these IOUs all signed Bonneville RD PSCs for FY 2011 through FY 2028, no IOUs have elected to take power service under these contracts thus no net requirement power sales are assumed for the IOUs through this study period.

Direct Service Industrial (DSI) Contracts

Bonneville currently has one DSI customer, Port Townsend Paper Corporation. DSI deliveries are forecasted at 11 aMW and expected to remain at that level throughout the study period.

Other Contract Obligations

Bonneville provides Federal power under a variety of additional contract arrangements. These contracts obligations are categorized as: 1) power sales; 2) power or energy exchanges; 3) capacity sales or capacity-for-energy exchanges; 4) power payment for services; and 5) power commitments under the Treaty. These arrangements, collectively referred to as "Other Contract Obligations", are determined by individual contract provisions and have various delivery arrangements and rate structures. These contracts include power deliveries to entities within the PNW region as Intra-Regional Transfers (Out), and to those outside of the PNW region as Exports.

Treaty, RD PSCs, and DSI power deliveries are assumed to remain in place throughout the study horizon. Bonneville's Other Contract Obligations follow individual contract terms and are not assumed to be renewed after the expiration date.

Conservation

The PSC obligation forecasts developed by the ALF are expected load forecasts, which include conservation identified by individual Bonneville customers. As an embedded assumption in the load

non-Federal resources or from BPA at rates reflecting BPA's marginal cost of acquiring the additional power, or through a mix of BPA Tier 2 priced power and non-Federal resources. (P.4 Regional Dialogue July 2007)

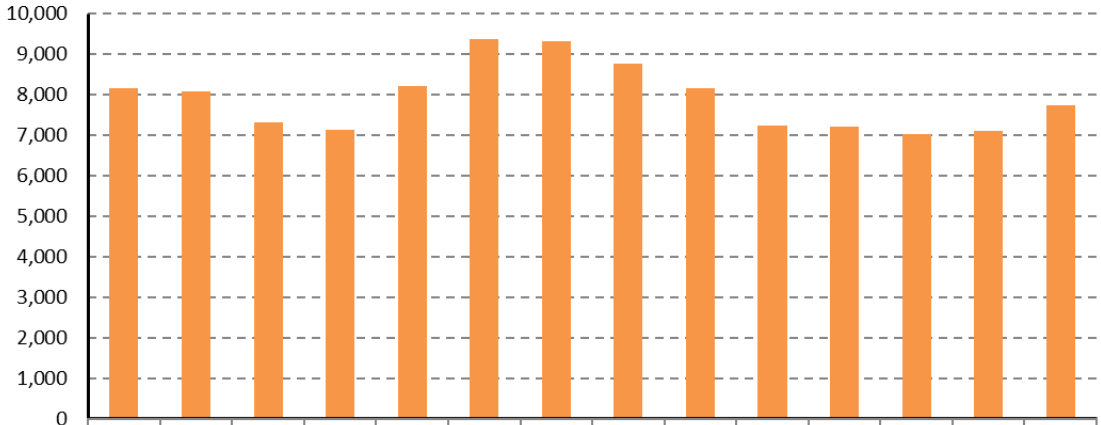
forecasts, it is expected that the historically embedded amount of conservation acquired will continue at the same rate going forward across the study period.

Firm Loads

The Federal system total firm load forecast shows a 4.3 percent average annual load growth over this study period. While Bonneville's forecast of PSC requirement loads increased roughly 9 percent over the study period, Bonneville's Exports and Intra-Regional Transfers (OUT) decreased due to the expiration or decrease in delivery of contracts.

Overall, the total Federal system load obligations remain relatively flat on an annual basis over the study period which is consistent with previous White Book studies due to the nature of Bonneville's RD PSCs. While on an annual basis these obligations demonstrate little variation across the study period, Bonneville's loads can vary greatly throughout the year. At a high level, Bonneville[7] experiences its highest loads in the late fall and winter months (November through March) primarily due to heating loads, with lower loads during spring, early summer and early fall months when temperatures are mild. July and August loads tend to be slightly higher than the rest of the summer months due to increasing air conditioning demands. Table 2-2 illustrates the monthly shape of the forecasted Federal system firm load obligations for OY2026.

Table 2-2 Federal System Firm Obligations for OY2026 - Monthly



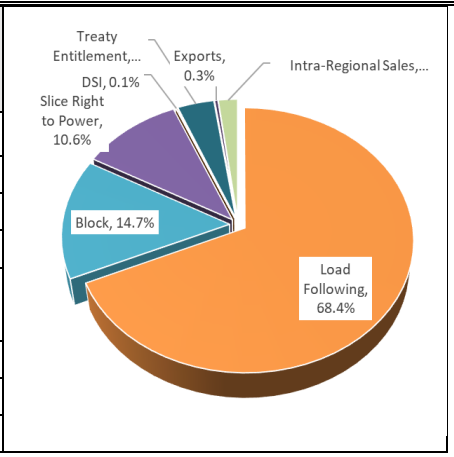
	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	8169	8087	7315	7126	8218	9374	9325	8762	8168	7242	7202	7038	7104	7730

Table 2-3 shows the annual make-up of the Federal system firm load obligations for OY2026 in Energy aMW.

[7] This is reflective of Bonneville's total aggregate loads, individual customers highest loads vary by month and season.

Table 2-3 Federal System Annual Firm Obligations by Category OY2026

Customer Class	RD PSCs	Energy (aMW)	Percent of Firm Energy
Load Following	Yes	5,443	68.4%
Block	Yes	1,171	14.7%
Slice Right to Power	Yes	843	10.6%
DSI	No	11	0.1%
Treaty Canadian Entitlement	No	305	3.8%
Exports	No	26	0.3%
Intra-Regional Sales	No	160	2.0%
Total Firm Obligations	**na**	**7,958**	**100%**



As previously noted, RD PSCs expire at the end of FY2028, and negotiations for new 19-year Provider of Choice PSCs are ongoing with contracts expected to be executed in December 2025. Given the uncertainty around post-2028 obligation levels, this study assumes a continuation of RD PSC load levels for planning purposes.

Resources

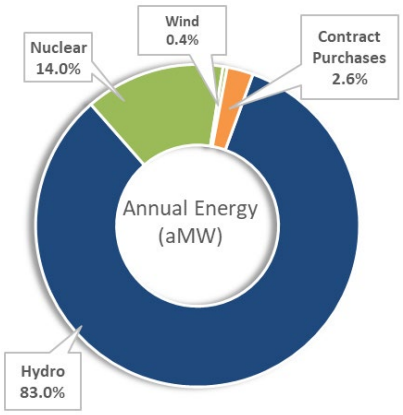
In the PNW, Bonneville is directed to market power from Federal hydroelectric projects and other resources acquired to meet firm power contractual obligations. By statute, Bonneville does not own generating resources, but instead, Bonneville markets power from Federal resources and non-Federal generating resources whose output Bonneville has acquired under contract. These resources and contract purchases are collectively referred to as "Federal system resources" in this study. Federal system resources are currently comprised of: 1) Hydro resources, which include regulated, independent, and small hydro projects; 2) Non-hydro renewable resources (wind projects); 3) Thermal resources, (Columbia Generating Station); and 4) Contract purchases, which are purchases from entities within the PNW region as Intra-Regional Transfers (In), including the estimated Mid-C Non-Federal Canadian Entitlement Return power (downstream benefit return as part of Columbia River Treaty) and from those outside of the PNW region as Imports.

Federal System Resource Types

Table 2-5 summarizes Bonneville's resources and contract purchases available to meet the Federal system load obligations. For OY2026, Federal system resources are forecast to produce 7,532 annual aMW of generation under Firm water conditions, with reserves and losses included.

Table 2-5 Federal System Generations by Resource Type for OY2026 - Firm Water Conditions

Resource Type	Annual Energy (aMW)	Percent of Firm Energy
Hydro	6,629	83%
Nuclear	1,116	14%
Wind	33	0.4%
Contract Purchases	209	2.6%
Total Federal Resources	7,988	100%
Reserves & losses	-455	--
Total Net Resources	7,532	--



Federal system contract purchases

Bonneville purchases or receives power under a variety of contract arrangements from entities within the PNW region as Intra-Regional Transfers (In), and from outside the region as Imports, to meet Federal system load obligations. These contract purchases, presented in Table 2-7 are made up of: 1) power purchases; 2) power or energy exchange purchases; 3) the estimated Mid-C Non-Federal Canadian Entitlement Return power; and 4) transmission loss returns under Slice/Block contracts. Bonneville's contract purchases are considered firm resources that are delivered to the Federal system regardless of weather, water, or economic conditions. Transmission loss returns capture the return of Slice/Block transmission losses to the Federal system as specified in the Slice/Block contract, and these returns are treated as Federal system resources. Except for the estimated Mid-C Non-Federal Canadian Entitlement Return power and transmission loss return of Slice/Block contracts, each contract purchase follows specific delivery terms and expiration dates and is not assumed to be renewed.

The Federal system resources are comprised of:

- Federal system hydro resources: Table 2-6 details the Federal system hydro resources from which Bonneville markets firm and non-firm power. Additionally, it shows the variability of individual Federal system hydro project generation for the three water conditions: firm, median, and high.
- Federal system non-hydro resources: Federal system non-hydro resources are generating resources whose output has been purchased by Bonneville. Table 2-7 details these generating resources, which include: 1) Columbia Generating Station; and 2) wind projects (non-hydro renewable resources). Forecasts for these resources are generally consistent from year to year but may change annually based on scheduling of annual maintenance, refueling, and capital improvements.

Table 2-6 Federal System Hydro Project Generation Forecasts by Streamflow Conditions[8] – OY2026

Project	Initial Service Date	Operator	Number of Units	Maximum Capacity [d/] (MW)	High [c/] Energy (aMW)	Median [c/] Energy (aMW)	Firm [a/c/] Energy (aMW)
Regulated Hydro							
1. Albeni Falls	1955	USACE	3	50	22.5	24.3	24.2
2. Dworshak	1974	USACE	3	465	274	184	171
3. Hungry Horse	1952	USBR	4	310	105	102	95
4. Libby	1975	USACE	5	605	262	242	195
5. Grand Coulee / GCL Pumping	1941	USBR	27	6,684	3,045	2,432	1,906
	1973		6	314			
6. Chief Joseph	1955	USACE	27	2,614	1,751	1,433	1,133
7. Lower Granite*	1975	USACE	6	930	259	159	134
8. Little Goose*	1970	USACE	6	930	315	178	154
9. Lower Monumental*	1969	USACE	6	930	290	172	145
10. Ice Harbor*	1961	USACE	6	693	254	167	143
11. McNary**	1953	USACE	14	1,120	676	543	447
12. John Day**	1968	USACE	16	2,480	1,221	910	771
13. The Dalles**	1957	USACE	22	2,080	955	801	639
14. Bonneville [b/]**	1938	USACE	18	1,221	711	512	395
15. Total Regulated Hydro Projects			**169**	**21,426**	**10,142**	**7,859**	**6,354**
Independent Hydro Projects							
16. Anderson Ranch	1950	USBR	2	40	15	13	9
17. Big Cliff***	1954	USACE	1	21	14	12	11
18. Black Canyon	1925	USBR	2	8.5	8	6	6
19. Boise Diversion	1908	USBR	3	2.5	2	1	1
20. Chandler	1956	USBR	2	12.2	8	7	6
21. Cougar***	1964	USACE	2	28	8	7	5
22. Cowlitz Falls	1994	LCPD#1	2	70	34	27	24
23. Detroit***	1953	USACE	2	115	33	26	24
24. Dexter***	1955	USACE	1	17	10	8	8
25. Foster***	1968	USACE	2	23	10	8	8
26. Green Peter***	1967	USACE	2	92	24	15	13
27. Green Springs	1960	USBR	1	18	7	7	7
28. Hills Creek***	1962	USACE	2	34	24	17	15
29. Lookout Point***	1954	USACE	3	138	11	18	15
30. Lost Creek	1975	USACE	2	56	38	37	30
31. Minidoka	1909	USBR	4	28	18	15	11
32. Palisades	1957	USBR	4	177	93	90	74
33. Roza	1958	USBR	1	14	9	8	7
34. Total Independent Hydro Projects			**38**	**894**	**365**	**323**	**273**
Small Non-Federally Owned Hydro Projects							
35. Dworshak/Clearwater Small Hydro	2000	ID DWR	1	5.4	2.6	2.6	2.6
36. Rocky Brook	1985	MCPD#1	1	1.6	0.3	0.3	0.3
37. Total Non-Federally Owned Hydro			**2**	**7**	**2.9**	**2.9**	**2.9**
38. Total Hydro Generation ***(line 15 + line 34 + line 37)***			**209**	**22,327**	**10,510**	**8,185**	**6,629**

* Lower Columbia Projects ** Lower Snake River Projects *** Willamette River Projects

a/ Firm energy is the 12-month annual average for OY 2025 assuming 10th percentile (P10) water conditions

b/ Bonneville Dam generation totals include Bonneville Fishway

c/ High Energy = 90th percentile, Median Energy = 50th percentile, Firm Energy = 10th percentile

d/ Maximum Capacity represent full capacity of resource including overload.

[8] Streamflow conditions do not always have a linear correlation with generation output. Projects with smaller head (head = forebay level minus tailwater level) are susceptible to having the inverse effect between flow and generation, e.g. Albeni Falls. Higher flow passes through the project increasing the tailwater level which results in less head, this results in lower generation than in other lower flow conditions.

Table 2-7 Federal System Non-Hydro Project Generation Forecast and Contract Purchase – OY2026

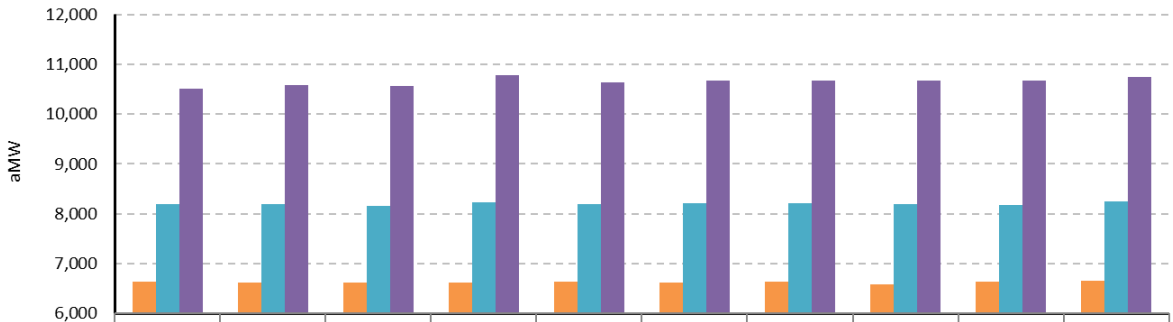
	Project	Initial Service Date	Resource Type	Operator	Maximum Capacity [a/] (Peak MW)	Firm Energy (aMW)
	Non-Hydro Resources					
1	Columbia Generating Station	1984	Nuclear	ENW	1,178	1,116
2	Stateline Wind Project [b/]	2001	Wind	PPM, FLP	0	21.2
3	Klondike Phase III [c/]	2007	Wind	NW Wind Power	0	11.8
4	Fourmile Hill Geothermal [d/]	Not in Service	Geo.	Calpine	0	0
5	**Total Federal System Non-Hydro Resources**				**1,178**	**1,149**
	Contract Purchases					
6	Canadian Entitlement for Canada (non-Federal)				147	84
7	Canadian Imports				1	1
8	Pacific Southwest Imports				0	0
9	Intra-Regional Transfers In (Pacific Northwest Purchases)				175	107
10	Slice Transmission Loss Return				29	17
11	**Total Federal System Contract Purchases**				**352**	**209**
12	**Total Federal System Non-Hydro Resources and Contract Purchases**				**1,530**	**1,358**

a/ This is the maximum generation for January 2025
b/ Stateline Wind Project contract expiring in 2028
c/ Klondike Phase III Project expiring in 2029
d/ Fourmile Hill is not assumed to be in operation within the study period

Federal System Hydro Generation Variability

The generating capacity of Federal system hydroelectric projects depends on the amount of water flowing through the facilities, the physical capacity of the facilities, flow requirements pursuant to biological opinions, a combination of other power and non-power constraints, and other operating limitations. Table 2-8 shows the annual variability of hydro generation under the three water conditions. Although hydro generation changes drastically from different water conditions, within each condition; however, it changes only slightly from year to year.

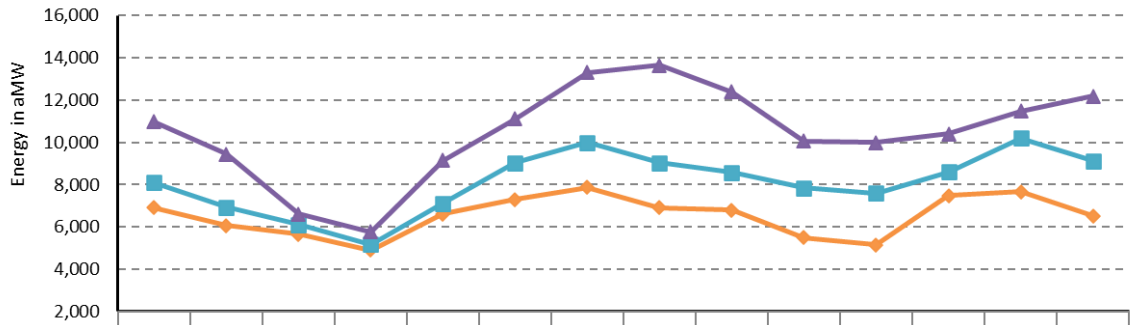
Table 2-8 Federal System Variability of Annual Hydro Generation by Streamflow Conditions – OY2026 – OY2035



	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Firm Water (P10)	6,629	6,616	6,623	6,625	6,634	6,622	6,645	6,589	6,635	6,651
Median Water (P50)	8,185	8,188	8,152	8,231	8,195	8,206	8,210	8,194	8,184	8,253
High Water (P90)	10,510	10,581	10,572	10,775	10,640	10,675	10,666	10,679	10,669	10,739

In OY2026, annual Federal system hydro energy generation is forecasted to be 6,629 aMW under Firm Water conditions. However, under the High Water conditions these same Federal system hydro resources could generate as much as 10,510 aMW. Table 2-9 displays the monthly variability of the Federal system hydro generation forecasted for OY2026, under the same three water conditions. Higher generation levels from January through March are largely due to drafting reservoirs for flood control and power production. Available water in those months depends greatly on annual rainfall and snowpack levels in the Columbia River Basin, and thus the generation exhibits large variability from year to year. Power production from April through July is variable based on the timing and amount of Columbia River Basin snowmelt runoff. Power production decreases through the end of summer and early fall as stream flows decline due to depleted snowpack and lower precipitation levels. Annual water volume variability generally has little impact on generation from the Federal system hydro resources in September and October. As observed from Table 2-9, hydro generation can vary by over 6,500 aMW in a single month, almost doubled in this case February, depending on operations and availability of water.

Table 2-9 Federal System Monthly Hydro Generation Variability by Streamflow Conditions – OY2026

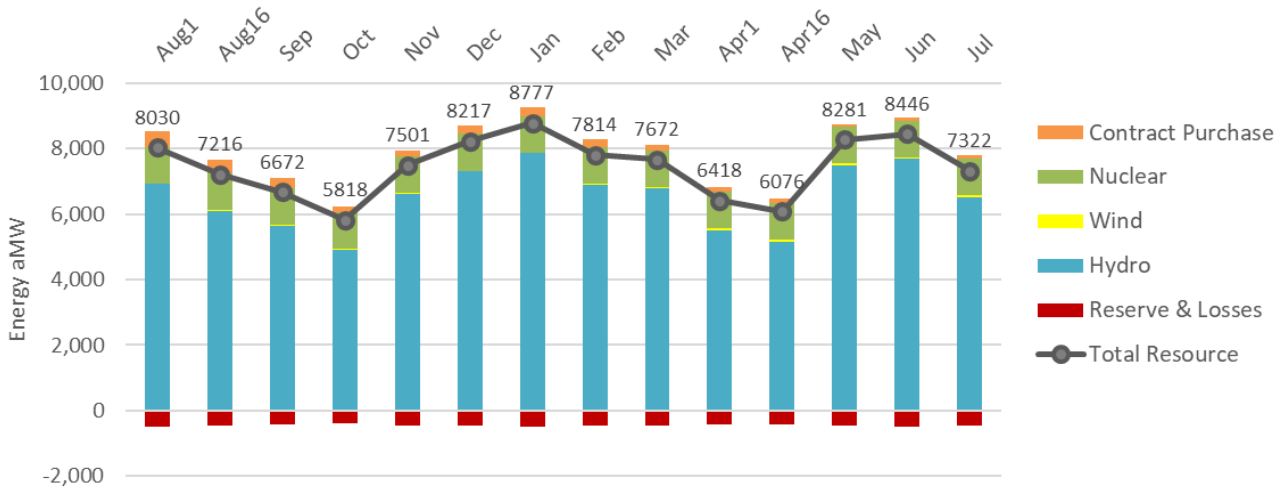


	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Firm Water (P10)	6,921	6,078	5,649	4,912	6,611	7,300	7,861	6,903	6,792	5,504	5,162	7,492	7,678	6,520
Median Water (P50)	8,108	6,945	6,121	5,189	7,129	9,043	10,000	9,045	8,573	7,851	7,607	8,599	10,206	9,118
High Water (P90)	10,972	9,448	6,620	5,779	9,153	11,113	13,307	13,648	12,387	10,056	9,998	10,393	11,487	12,178

Total Federal System Resources

Table 2-10 shows the monthly shape of forecasted total Federal system generation for energy (in aMW) for OY2026, under Firm water conditions. This includes generation from all Federal system hydro and non-hydro resources, as well as contract purchases. Overall, the Federal system has the highest net generation forecasted in winter months to early spring and mid-summer periods.

Table 2-10 Federal System Monthly Generation for OY2026 under Firm Water Conditions



Key Results

Annual Energy

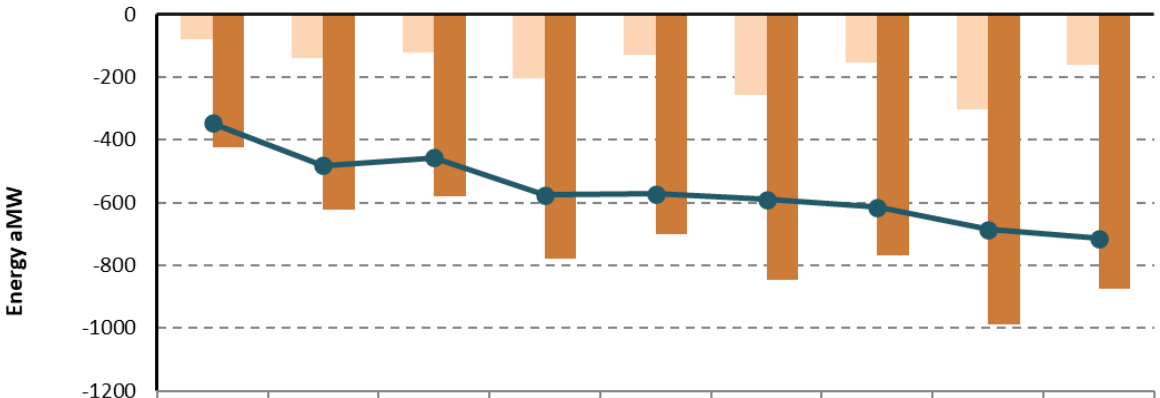
Table 2-11 shows that the Federal system is forecasted to have annual energy deficits throughout the study period. The individual components of the Federal system annual energy loads and resources are shown in Exhibit 4-1 for OY2026 through OY2035. The Federal system detailed monthly energy loads and resources are shown in Exhibit 4-2 for OY2026.

Table 2-11 Federal System Annual Energy Surplus/Deficit under Firm Water Conditions

Energy (aMW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Surplus/ Deficits	-426	-622	-580	-778	-701	-846	-768	-988	-876	-1012

Table 2-12 compares the 2025 White Book Federal system annual firm energy surplus/deficit results to those from the 2024 White Book. In this comparison, the 2025 White Book shows a consistent increase in deficits annually throughout the studying period. These results reflect changes in both Federal load obligations and Federal system generations.

Table 2-12 Federal System Annual Energy Surplus/Deficits Comparison under Firm Water

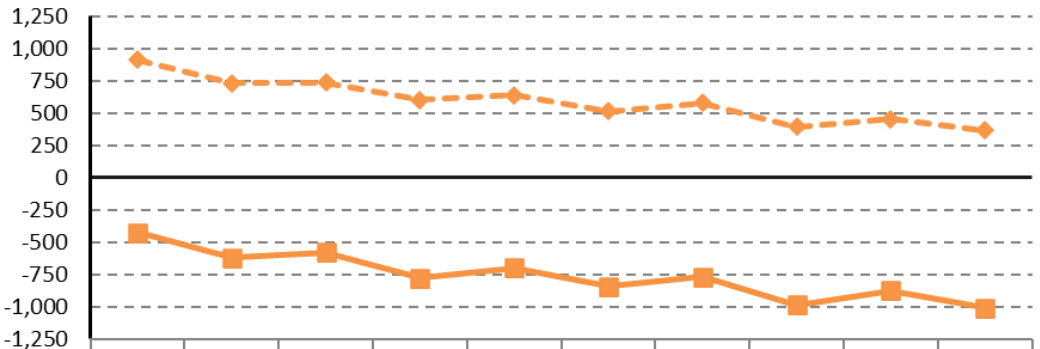


	2026	2027	2028	2029	2030	2031	2032	2033	2034
2024 White Book	-79	-139	-122	-203	-128	-257	-153	-303	-161
2025 White Book	-426	-622	-580	-778	-701	-846	-768	-988	-876
Delta	-346	-482	-457	-575	-572	-589	-615	-685	-715

Federal System Annual Surplus/ Deficit

Table 2-13 graphically presents the annual firm and median conditions energy surplus/deficits. Over the study period, the Federal system is forecasted to have a deficit in annual firm energy as high as 1,012 aMW in the last year of the study period. Noticeable differences in annual energy between odd and even years can be attributed to the biennial Columbia Generation Station (CGS) maintenance schedule[9]. Under Median Water conditions, the Federal System is surplus throughout the study period.

Table 2-13 Federal System Annual Surplus/ Deficits Under Firm Water Conditions



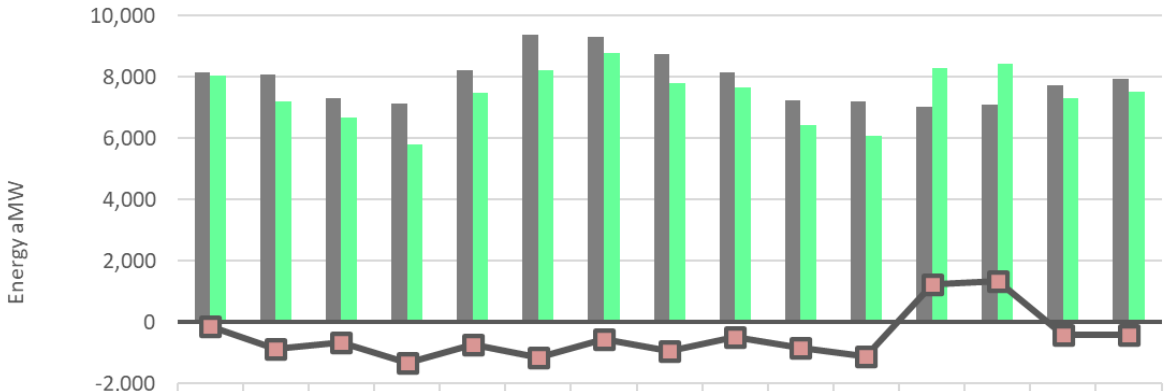
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy (aMW)	-426	-622	-580	-778	-701	-846	-768	-988	-876	-1,012
Energy (aMW) p50	911	729	734	601	639	514	576	390	454	364

[9] CGS has routine maintenance cycle scheduled in odd calendar years, specifically in months of May and June. CGS is forecast to produce 994 aMW annually during maintenance years, and 1,116 aMW annually during non-maintenance years.

Federal System Monthly Surplus/ Deficit

Table 2-14 displays a graphic look at the Federal system monthly firm energy surplus/deficits for OY2026. Largest deficit comes in the month of October and better positions in the months of May and June, after spring run-off.

Table 2-14 Federal System Monthly Surplus/ Deficits OY2026 under Firm Water Conditions



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

Conclusion

Under Firm water conditions, the Federal system shows annual firm energy deficits through the 2026-2035 study period. These annual energy deficits range from 426 aMW in OY2026 to as high as over 1,000 aMW in OY2035. At a monthly resolution under Firm water conditions, the Federal system generally shows larger energy deficits across the winter and early spring periods until spring runoff starts, which then turns into surplus from May and to the early summer periods.

The Federal system surplus/deficit forecasts generally have a positive relationship with water conditions. Better water conditions generally yield more surplus overall. For example, the annual energy surplus can increase by over 4,000 aMW under better water conditions, while monthly surplus or deficit position can vary by over 5,500 aMW within the same year.

The range of Federal system monthly surplus and deficit forecasts under all 30-water years is presented in Exhibit 4-3. Additional monthly and annual details for OY2026 through OY2035 are available upon request, a list of available data reports can be found in the Appendix. Reminder: Data Report requests can be sent to WhiteBook@bpa.gov.

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SECTION 3: PACIFIC NORTHWEST REGIONAL ANALYSIS

The PNW Regional Analysis is an OY analysis that provides Bonneville's deterministic forecast of the PNW region's loads and resources over a 10-year period from OY 2026 through OY 2035. Firm load and resources forecasts are presented in energy based on regional retail loads, contract obligations, and resources. This White Book analysis assumes that generation from all regional uncommitted Independent Power Producer (IPP) projects is available to meet regional load. Regional retail loads, contract sales and purchases, and generating resources forecasts incorporate annual regional utility data submittals received by Bonneville.

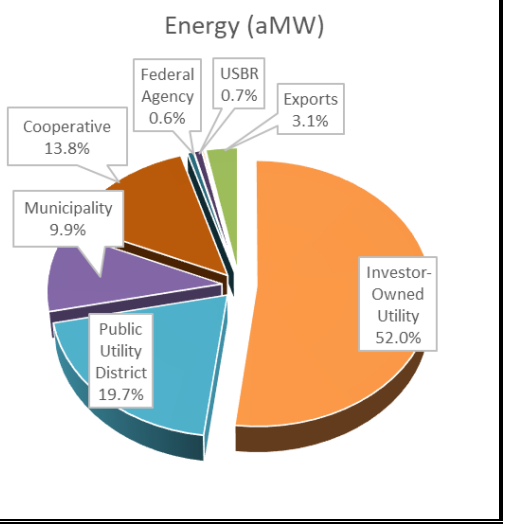
Regional Loads

The regional analysis incorporates regional load projections, which consist of two separate components: 1) Total Retail Loads (TRL), which is the sum of individual utilities' retail power consumption within the PNW region; and 2) Regional contract sales (Exports), which are the sum of all reported long-term regional contract deliveries to entities outside the PNW region. The TRL forecasts for the regional analysis are developed by Bonneville's ALF system. TRL forecasts reflect normal weather conditions, include historical conservation savings, and do not include specific adjustments for evolving climate trends. Apart from power commitments under the Treaty, all Export contract deliveries follow individual contract terms and are not assumed to be renewed after their expiration dates. Treaty power deliveries are assumed to be in place throughout the study period. The sum of the forecasted TRL and Export contracts represents the regional loads for the PNW.

Regional loads are comprised of roughly 96 percent retail loads and four percent exports. Table 3-1 shows the forecasted composition of PNW regional load for OY2026.

Table 3-1 PNW Region Firm Loads by Customer Category – OY2026

Customer Class	Energy (aMW)	Percent of Firm Energy
Investor-Owned Utility	13,617	52%
Public Utility District	5,518	19%
Municipality	2,582	10.2%
Cooperative	3,624	14.3%
Federal Agency	157	1%
USBR	192	0.8%
DSI	51	0.2%
Marketer	0	0.0%
Total Retail Load	**25,380**	**97%**
Exports	814	3.9%
Total Regional Load	**26,194**	**100%**



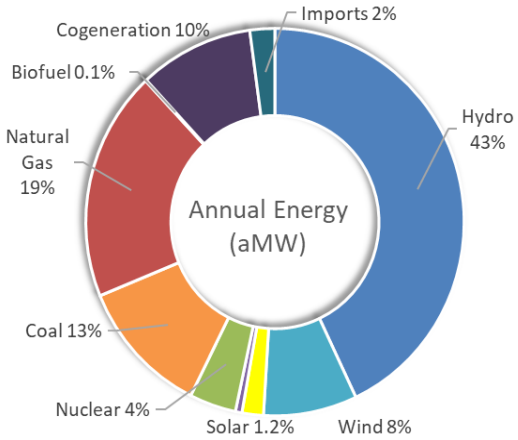
Regional Resources

PNW resources and contract purchases are collectively called "regional resources" in this study. Similarly to the Federal system resources, regional resources vary monthly by water conditions, resource type, and seasonality of generating resource potential. This analysis classifies resources as 1) Hydro resources, which include regulated, independent, and small hydro projects; 2) Non-hydro renewable resources which include wind, solar, and other projects; 3) Thermal resources which include nuclear, coal, natural gas, petroleum, biofuel and cogeneration projects; and 4) Contract purchases which are identified as Imports.

Table 3-3 summarizes the resource generation available to meet PNW regional loads. The generation forecasts for these resources are provided by Bonneville models or the project owners. New regional generating projects are included when those resources begin operating or are under construction and have a scheduled on-line date; similarly, retiring resources are removed from the forecasts based on the data of the announced retirement date. Contract purchases are provided by the individual utility, follow specific contract provisions, and can have various delivery arrangements.

Table 3-3 PNW Regional Generations by Resource Type – OY2026 Firm Water Conditions

Project Type	Annual Energy (aMW)	Percent of Energy
Hydro	12,013	43%
Wind	2,240	8%
Solar	510	1.8%
Other Renewable	157	0.6%
Nuclear	1,116	4%
Coal	3,201	11%
Natural Gas	5,371	19%
Petroleum	0	0%
Biofuel	26	0.1%
Cogeneration	2,730	10%
Imports	597	2%
Total Regional Resources	**27,960**	**100%**



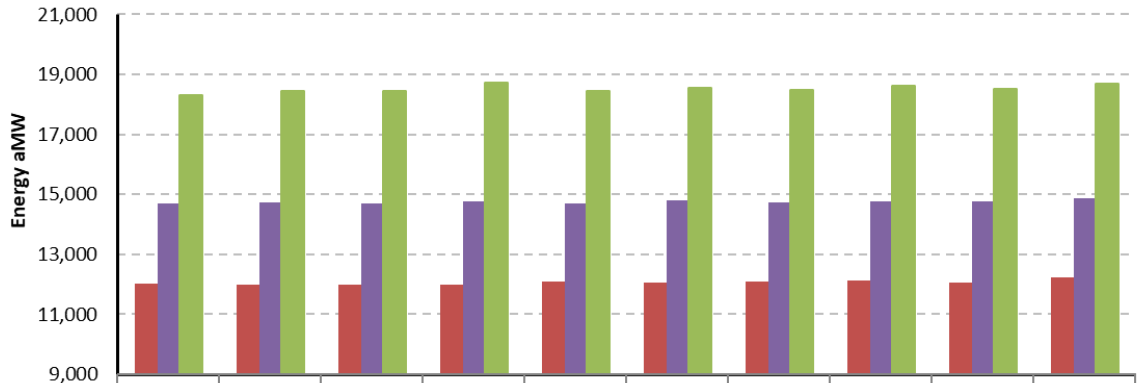
Regional Hydro Generation Variability

The generating capacity of regional hydroelectric projects depends upon the amount of water flowing through the facilities, the physical capacity of the facility, flow requirements pursuant to non-power requirements, and other operating limitations. Similarly to Federal Hydro Resources, Bonneville utilizes the 30-year streamflow record for planning purposes. Similarly, three water conditions are presented here to represent the magnitude of hydro generation variability.

Table 3-4 shows the annual variability of the region's hydro generation under the three streamflow scenarios. Details on the different streamflow scenarios please refer to Hydro Resource Modeling section.

In OY2026, annual firm energy generation from regional hydro projects is forecasted to be 12,013 aMW under the firm water conditions, and this represents about 43% of the region's resources. However, the generating potential from regional hydro projects can vary annually by over 6,000 aMW between firm and high water conditions.

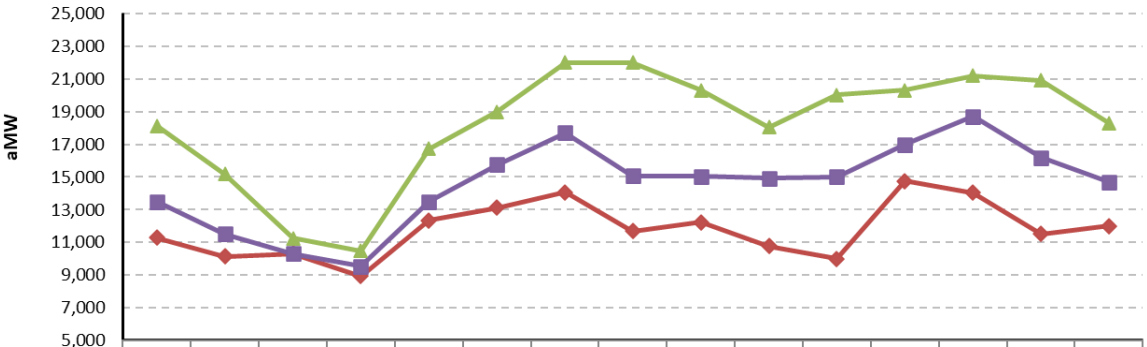
Table 3-4 PNW Regional Annual Variability of Hydro Generation by Streamflow Conditions



	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Firm Water (P10)	12,013	11,971	12,005	11,991	12,085	12,056	12,094	12,130	12,048	12,235
Median Water (P50)	14,687	14,741	14,684	14,756	14,709	14,813	14,724	14,766	14,749	14,874
High Water (P90)	18,303	18,444	18,452	18,732	18,447	18,554	18,476	18,620	18,512	18,675

Table 3-5 shows the monthly variability of regional hydro generation under the same three water conditions for OY2026. The increased level of generation in January through March is largely due to drafting reservoirs for power production and flood control, which can vary widely due to rainfall and snowpack levels in the Columbia River Basin. Power production fluctuations in the second half of April through July are highly related to the timing and amount of Columbia River Basin snowmelt runoff. Power production decreases through the end of summer and early full as streamflow are reduced due to depleted snowpack and lower precipitation levels. Water variability does not have a substantial impact on regional hydro generation from September through October as those are the months with overall lowest water availabilities. Regional hydro generation capability can vary by as much as 10,000+ aMW between firm and high water conditions within the same month.

Table 3-5 PNW Regional Hydro Generation Monthly Variability by Streamflow Conditions - OY2026



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
Firm Water (P10)	11,278	10,148	10,313	8,946	12,350	13,126	14,067	11,686	12,234	10,785	9,998	14,753	14,029	11,502	12,013
Median Water (P50)	13,487	11,523	10,305	9,538	13,496	15,761	17,699	15,064	15,053	14,935	15,002	16,984	18,711	16,195	14,687
High Water (P90)	18,127	15,191	11,250	10,479	16,727	18,990	21,999	22,004	20,300	18,056	20,015	20,309	21,207	20,922	18,303

Uncommitted IPP Generation Delivered to the PNW Region

The PNW regional study includes uncommitted PNW IPP generation as regional resources. These resources, or the share of these resources that are not committed to serving specific loads, represent approximately 2,550 aMW of energy for OY2026. The inclusion of this uncommitted IPP generation is reasonable from the long-term planning perspective because the PNW Regional Analysis does not include any reliance on market purchases. However, PNW utilities may have to compete with other western markets to secure this generation to meet electricity demands. Table 3-6, next, details the region's total uncommitted IPP annual energy generation forecasts over the OY2026 through OY2035 study period.

Table 3-6 PNW Regional Annual Uncommitted IPP Generation

Regional Uncommitted IPP	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Annual Energy (aMW)	2,550	2,474	2,503	2,513	2,510	2,512	2,508	2,508	2,508	2,519

Table 3-7 details the region's uncommitted IPP projects and the associated fuel types. If uncommitted IPP generation is secured for long-term periods by load serving entities within the region or outside the region, the IPP forecasts will be updated in future studies to reflect those changes.

Table 3-7 PNW Regional Uncommitted Independent Power Producer Projects – OY2026 Firm Water Conditions

Project	Fuel Type	Energy (aMW)
Airport Solar	Solar	13
Centralia Complex [a/b/]	Coal	91
Clearwater Wind	Wind	23
Condon Wind	Wind	12
Cosmopolis Specialty Fibres	Wood Waste	14
Goose Prairie Solar	Solar	17
Hermiston Power Project	Wood Waste	567

Project	Fuel Type	Energy (aMW)
International Paper Energy Center	Wood Waste	16
Juniper Canyon Wind	Wind	36
Kittitas Valley Wind	Wind	24
Klamath Generation Facility	Natural Gas	436
Klamath Generation Peakings (CT)	Natural Gas	90
Klondike Wind 1	Wind	6
Klondike Wind 3	Wind	23
Klondike Wind 3a	Wind	18
Leaning Juniper Wind	Wind	47
Longview Fibre Paper & Packaging	Wood Waste	35
Nippon Paper Cogen (Port Angeles)	Wood Waste	5
Pelton	Hydro	14
Priest Rapids	Hydro	85
Rock Island	Hydro	84
Rocky Reach	Hydro	156
Round Butte	Hydro	31
Satsop Combustion Turbine Project	Natural Gas	584
SDS Lumber	Wood Waste	1
Smith Creek (Idaho)	Hydro	7
Stateline Wind	Wind	8
Stimson Lumber (Plummer)	Wood Waste	7
Tacoma Biomass (WestRock)	Wood Waste	0
Tieton Dam (Yakima)	Hydro	0
Vansycle Wind	Wind	23
Wanapum	Hydro	25
Weyerhaeuser Longview	Wood Waste	35
Willow Creek Wind	Wind	17
Total Uncommitted IPP Generation		**2,550**

[a/] Centralia #2 (670 MW) is scheduled for retirement on Dec 1, 2025. Puget purchased an increasing amount of this project beginning Dec 1, 2014 and ending Nov 30, 2025.

Key Results

Annual Energy

Table 3-8 shows annual energy surpluses for the PNW region in the first two operating years, then increasingly more deficit going forward to outyears. This study assumes that 100 percent of the PNW region's uncommitted IPP generation (2,550 aMW in OY2026 is available to serve regional loads. The individual components of the PNW regional annual energy loads and resources for OY2026 through OY2034 are shown in Exhibit 5-1, and OY2026 monthly PNW regional details are shown in Exhibit 5-2. Other details of each component for OY2026 through OY2035 are available upon request via email at WhiteBook@bpa.gov.

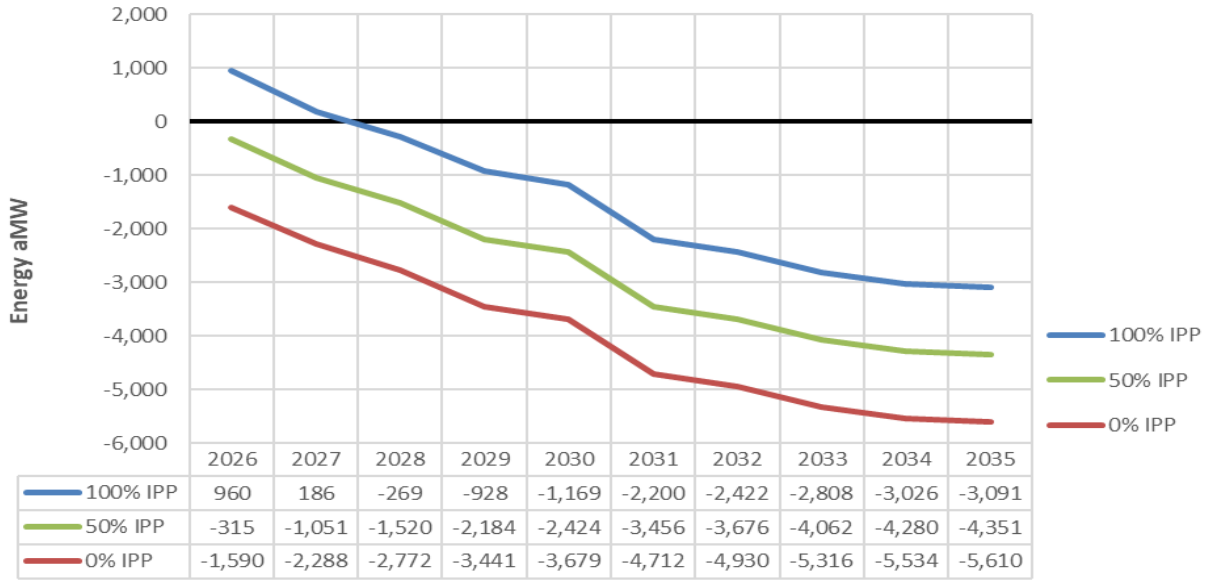
Table 3-8 PNW Regional Annual Energy Surplus/ Deficit - Firm Water Conditions

Assuming 100% of Uncommitted IPP Generation is Available to the Region

Energy (aMW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Surplus/ Deficit	960	186	-269	-928	-1,169	-2,220	-2,422	-2,808	-3,026	-3,091

Table 3-9 shows the significant variability in PNW regional annual firm energy surplus/deficit forecasts depending on the level of uncommitted IPP generation available to the region. IPP generation is detailed in Tables 3-6 and 3-7.

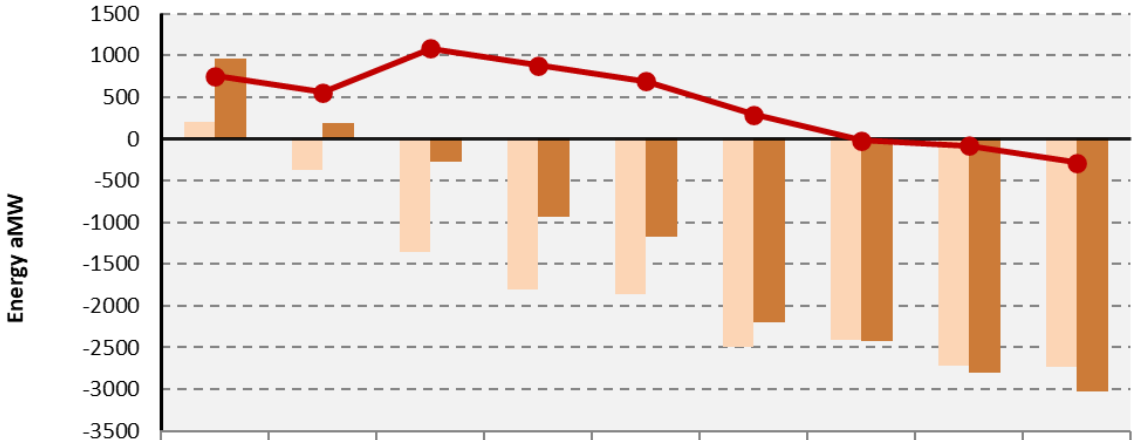
Table 3-9 PNW Regional Annual Energy Surplus/ Deficit by Uncommitted IPP Generation %



	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
100% IPP	960	186	-269	-928	-1,169	-2,200	-2,422	-2,808	-3,026	-3,091
50% IPP	-315	-1,051	-1,520	-2,184	-2,424	-3,456	-3,676	-4,062	-4,280	-4,351
0% IPP	-1,590	-2,288	-2,772	-3,441	-3,679	-4,712	-4,930	-5,316	-5,534	-5,610

Table 3-10 compares the 2025 White Book PNW regional annual firm energy surplus/ deficit forecasts to that of the 2024 White Book. The comparison shows significant change, the 2025 White Book shows OY2026 to have over 700 aMW more surplus energy available, and this continues through OY2028 where 2025 White Book forecast showed over than 1,000 aMW of change resulting in less deficit than forecasts from 2024 White Book. This change is mainly driven by the decrease in the PNW Regional Retail Load, more specifically in the new large industrial loads category. By OY2032 the forecasted regional position is very similar to the 2024 White Book, with growing deficits after that point in the study.

Table 3-10 PNW Regional Annual Surplus/ Deficit Comparison – Firm Water Conditions Assuming 100% Uncommitted IPP Generations available to the Region

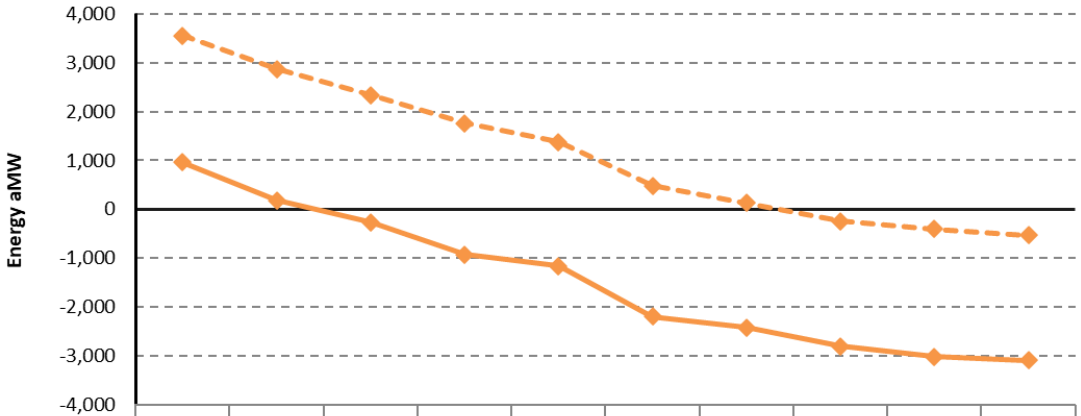


	2026	2027	2028	2029	2030	2031	2032	2033	2034
2024 White Book	207	-370	-1352	-1808	-1861	-2492	-2407	-2725	-2738
2025 White Book	960	186	-269	-928	-1169	-2200	-2422	-2808	-3026
Delta	753	556	1084	880	692	293	-15	-84	-288

Regional Annual Surplus/ Deficit

Table 3-14 graphically presents the annual firm energy surplus/ deficit forecasts for the PNW region under firm (P10) and median (P50) conditions. These forecasts assume 100 percent availability of the PNW uncommitted IPP generation to serve the region's loads. The regional annual energy surplus/ deficit declines over the 10-year study period.

Table 3-14 PNW Regional Annual Surplus/ Deficit – Firm & Median Water Conditions

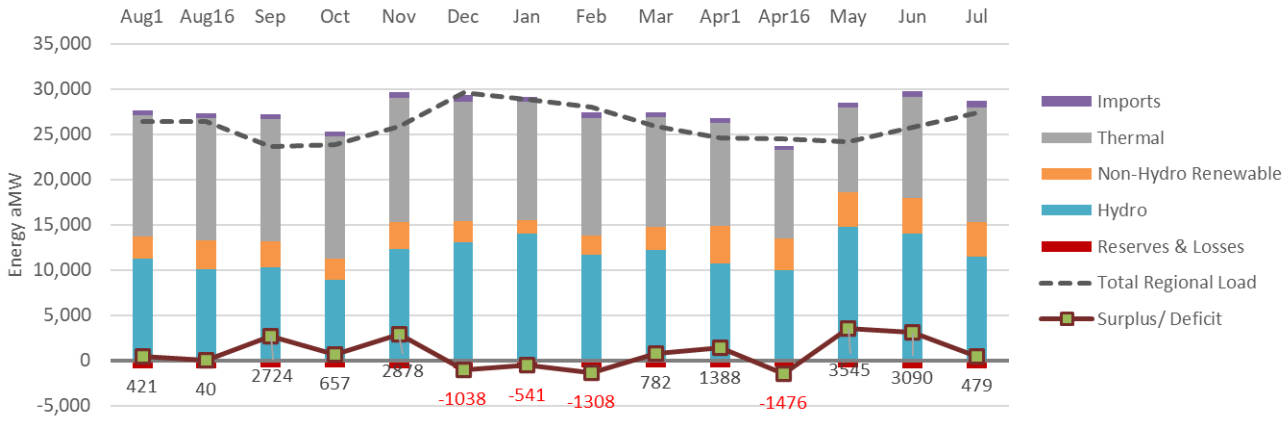


	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy P10	960	186	-269	-928	-1,169	-2,200	-2,422	-2,808	-3,026	-3,091
Energy P50	3557	2876	2333	1758	1378	477	132	-248	-403	-529

Regional Monthly Surplus/ Deficit

Table 3-15 shows the monthly energy surplus/ deficit forecast for OY2026, accompanied with monthly total firm obligations and resources by category. Again, these forecasts assume 100 percent of uncommitted IPP generation serving the region. This monthly view shows how both metrics follow a similar monthly shape with most surplus months in late spring to the beginning of summer when hydro generation is high, and most deficits around the second half of April, before the runoff begins historically and as fish operations begin.

Table 3-15 PNW Regional Monthly Surplus/ Deficit – OY2026 Firm Water Conditions



Conclusion

The PNW region is projected to have annual firm energy surpluses in the first two operating years, with surpluses declining and quickly becoming deficits and growing into larger deficits going into the outyears, under the assumption of 100 percent of the PNW region's uncommitted IPP generation available to serve the region's load. Additionally, because of the full uncommitted IPP generation assumption to serve the region's load, with its uncommitted nature, the supply of power within the region can change dramatically and quickly if those resources were to be used to serve loads outside of the region or retire early or unexpectedly. Under the median (P50) water conditions, the PNW region sees surpluses until the outyears of OY 2032.

Notably, the region's retail load forecasts adjusted downwards significantly in the front half of the study period from 2024 Whtie Book forecast, this is driven by the uncertainty of the new large single load category of the retail loads.

Detailed surplus/deficit forecasts for all 30-historical water conditions are presented in Exhibit 5-3; monthly and annual details for OY2026 through OY2035 are available upon request with the itemized list located in the Appendix.

The regional energy deficits identified in this study may be mitigated through resource options discussed in the NWPCC's Power Plan publications, NWPCC is currently working on updating their

2021 Northwest Power Plan[10] and it is updated roughly every 5 years. Bonneville provides this PNW regional planning analysis for informational purposes only.

[10] The 2021 Northwest Power Plan (nwcouncil.org)

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SECTION 4: FEDERAL SYSTEM ANALYSIS EXHIBITS

Exhibit 4-1: Annual Energy – Federal System Surplus/ Deficit: Operating Years 2026 – 2035, Firm Water Conditions

Loads and Resources - Federal System Percentile
Operating Year: 2026 to 2035 Percentile: 10
White Book 2025 (Energy Only) Report Date: **4/16/2025**
S268-WB-20250415-174748

	Energy-aMW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Firm Obligations										
1	**Load Following**	5443	5525	5581	5665	5718	5767	5810	5859	5895	5930
2	Preference Customers	5096	5175	5225	5300	5349	5396	5437	5483	5517	5550
3	Federal Agencies	155	158	161	168	172	174	176	179	181	183
4	USBR	192	192	194	197	197	197	197	197	197	197
5	Federal Diversity	0	0	0	0	0	0	0	0	0	0
6	**Tier 1 Block**	560	573	586	583	588	590	590	590	589	589
7	Tier 1 Block	560	573	586	583	588	590	590	590	589	589
8	**Slice**	1454	1439	1441	1430	1440	1435	1439	1431	1438	1435
9	Slice Block	611	613	601	604	595	600	588	601	588	598
10	Slice Output from T1 System	843	826	839	826	845	835	851	830	850	838
11	**Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
12	Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
13	**Contract Deliveries**	491	340	328	328	301	246	247	246	247	247
14	Exports	331	317	318	317	290	237	237	237	238	237
15	Intra-Regional Transfers (Out)	160	22.4	10.7	10.7	10.7	9.44	9.44	9.44	9.44	9.44
16	**NR Obligation**	0	16.8	24.1	31.2	33.4	46.8	58.9	64.6	73.9	75.0
17	NR Rate Load	0	16.8	24.1	31.2	33.4	46.8	58.9	64.6	73.9	75.0
18	**Total Firm Obligations**	**7958**	**7905**	**7971**	**8048**	**8092**	**8096**	**8156**	**8202**	**8254**	**8286**
	Net Resources										
19	**Hydro**	6629	6616	6623	6625	6634	6622	6645	6589	6635	6651
20	Regulated Hydro - Net	6354	6344	6353	6353	6355	6340	6367	6326	6379	6391
21	Independent Hydro - Net	273	269	267	269	276	279	275	260	253	257
22	Small Hydro - Net	2.88	2.88	2.88	2.88	2.88	2.88	2.87	2.88	2.88	2.88
23	**Non-Hydro Renewable**	33.0	19.8	1.90	0	0	0	0	0	0	0
24	Wind - Net	33.0	19.8	1.90	0	0	0	0	0	0	0
25	Other - Net	0	0	0	0	0	0	0	0	0	0
26	**Thermal**	1116	994	1116	994	1116	994	1116	994	1116	994
27	Nuclear - Net	1116	994	1116	994	1116	994	1116	994	1116	994
28	**Contract Purchases**	209	102	102	99.2	91.3	80.7	77.6	77.0	77.5	77.3
29	Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
30	Intra-Regional Transfers (In)	107	0	0	0	0	0	0	0	0	0
31	Non-Federal CER	84.0	84.0	83.8	82.5	75.0	64.6	61.2	60.9	61.1	61.1
32	Slice Transmission Loss Return	17.3	16.9	17.2	15.8	15.3	15.1	15.4	15.0	15.4	15.2
33	**Reserves & Losses**	-455	-448	-451	-447	-451	-447	-451	-446	-451	-447
34	Operating Reserves	0	0	0	0	0	0	0	0	0	0
35	Balancing Reserves	0	0	0	0	0	0	0	0	0	0
36	Transmission Losses	-232	-225	-228	-224	-228	-224	-228	-223	-228	-225
37	Wheeling Loss (financial settlement)	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223
38	**Total Net Resources**	**7532**	**7283**	**7392**	**7270**	**7391**	**7250**	**7387**	**7214**	**7378**	**7275**
39	**Total Surplus/Deficit**	**-426**	**-622**	**-580**	**-778**	**-701**	**-846**	**-768**	**-988**	**-876**	**-1012**

Exhibit 4-2: Monthly Energy – Federal System Surplus/ Deficit: Operating Year 2026, Firm Water Conditions

Loads and Resources - Federal System Percentile
Operating Year: 2026 Percentile: 10
White Book 2025 (Energy Only) Report Date: **4/16/2025**
S268-WB-20250415-174748

	Energy-aMW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
	Firm Obligations															
1	**Load Following**	5284	5250	4639	4843	5337	6325	6337	5969	5478	5171	5171	5076	5244	5640	5443
2	Preference Customers	4802	4761	4219	4570	5166	6136	6140	5757	5250	4771	4771	4600	4733	5048	5096
3	Federal Agencies	140	139	116	140	167	185	188	199	171	145	145	130	129	148	155
4	USBR	342	350	304	133	3.79	3.73	8.80	13.3	56.9	255	255	345	382	444	192
5	Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	**Tier 1 Block**	367	365	610	519	847	848	929	874	829	413	413	148	21.3	333	560
7	Tier 1 Block	367	365	610	519	847	848	929	874	829	413	413	148	21.3	333	560
8	**Slice**	1461	1356	1323	1210	1478	1644	1702	1561	1508	1305	1265	1462	1485	1380	1454
9	Slice Block	615	615	602	554	613	701	696	664	628	594	594	536	546	582	611
10	Slice Output from T1 System	846	741	721	656	865	943	1006	896	879	711	671	926	940	798	843
11	**Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11
12	Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11
13	**Contract Deliveries**	1045	1105	733	543	545	546	346	347	342	343	343	341	343	366	491
14	Exports	485	550	376	305	305	305	305	305	305	305	305	305	305	328	331
15	Intra-Regional Transfers (Out)	561	554	357	238	240	241	41.3	42.0	37.4	38.3	38.3	36.3	38.3	37.4	160
16	**NR Obligation**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	NR Rate Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	**Total Firm Obligations**	**8169**	**8087**	**7315**	**7126**	**8218**	**9374**	**9325**	**8762**	**8168**	**7242**	**7202**	**7038**	**7104**	**7730**	**7958**
	Net Resources															
19	**Hydro**	6921	6078	5649	4912	6611	7300	7861	6903	6792	5504	5162	7492	7678	6520	6629
20	Regulated Hydro - Net	6587	5746	5356	4794	6268	7053	7564	6743	6613	5227	4883	7139	7275	6220	6354
21	Independent Hydro - Net	331	330	291	115	340	243	294	158	175	274	276	350	401	297	273
22	Small Hydro - Net	2.63	2.63	2.63	2.67	2.84	3.19	3.21	3.05	3.10	3.09	3.09	2.83	2.72	2.63	2.9
23	**Non-Hydro Renewable**	22.6	33.8	31.5	25.3	36.2	27.6	14.8	24.4	28.1	50.2	42.3	45.2	44.7	43.7	33
24	Wind - Net	22.6	33.8	31.5	25.3	36.2	27.6	14.8	24.4	28.1	50.2	42.3	45.2	44.7	43.7	33
25	Other - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	**Thermal**	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116
27	Nuclear - Net	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116
28	**Contract Purchases**	454	446	301	164	188	244	271	228	190	165	164	102	106	103	209
29	Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.0
30	Intra-Regional Transfers (In)	350	350	200	64.5	88.3	139	164	125	89.0	64.4	64.4	0	0	0	107
31	Non-Federal CER	84.9	79.6	85.2	85.4	81.6	85.3	85.3	84.0	82.3	84.9	84.9	81.8	84.9	85.3	84
32	Slice Transmission Loss Return	17.6	15.4	14.7	13.3	17.6	19.2	20.5	18.2	17.9	14.5	13.7	18.8	19.6	16.6	17
33	**Reserves & Losses**	-483	-458	-426	-400	-450	-470	-486	-458	-454	-418	-409	-474	-498	-461	-455
34	Operating Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Balancing Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Transmission Losses	-260	-235	-203	-177	-227	-248	-263	-235	-231	-195	-186	-251	-275	-238	-232
37	Wheeling Loss (financial settlement)	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223
38	**Total Net Resources**	**8030**	**7216**	**6672**	**5818**	**7501**	**8217**	**8777**	**7814**	**7672**	**6418**	**6076**	**8281**	**8446**	**7322**	**7532**
39	**Total Surplus/Deficit**	**-139**	**-871**	**-643**	**-1,308**	**-716**	**-1,157**	**-549**	**-948**	**-497**	**-825**	**-1,127**	**1,243**	**1,342**	**-408**	**-426**

Exhibit 4-3: 30-Water Year Conditions Monthly Energy – Federal System Surplus/ Deficit: Operating Year 2026

Federal Report Surplus Deficit By Water Year
Operating Year 2026
White Book 2025 (Energy Only) Report Date: **4/17/2025**
S268-WB-20250415-174748

	Energy-aMW - Surplus Deficit	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
1	1989 Federal Report Surplus Deficit	154	822	-665	-1308	-686	-17.5	77.7	-112	204	584	1923	2195	1794	41.1	274
2	1990 Federal Report Surplus Deficit	112	-546	-365	-866	-270	1921	1303	2785	805	1017	1798	1998	4095	3316	1314
3	1991 Federal Report Surplus Deficit	2618	2020	1.61	-1443	1533	2041	2826	3837	1752	1703	975	2249	3351	4151	1985
4	1992 Federal Report Surplus Deficit	3140	1568	-432	-1231	-198	-1157	-423	-464	-366	-679	-1092	1900	1204	-704	-31.6
5	1993 Federal Report Surplus Deficit	147	-580	-390	-1308	-516	-1212	-1141	-2361	-505	277	-1498	2604	2547	1172	-149
6	1994 Federal Report Surplus Deficit	860	-126	-6.29	-1385	-325	-1236	-878	-493	-364	-1140	161	1415	1342	-289	-198
7	1995 Federal Report Surplus Deficit	96.1	-850	-238	-1265	-606	-740	572	1729	1764	39.2	-337	1447	3637	2401	671
8	1996 Federal Report Surplus Deficit	1672	345	193	-281	2554	5131	5418	5883	5309	1988	3031	3002	4581	4446	3299
9	1997 Federal Report Surplus Deficit	2858	1238	309	-1035	-8.05	2120	5484	5729	4739	2525	4026	4257	5141	4376	3021
10	1998 Federal Report Surplus Deficit	3337	2881	1136	1094	1394	946	1289	2058	1129	-169	-432	3844	4196	2498	1867
11	1999 Federal Report Surplus Deficit	2990	805	-2.69	-1188	-716	1110	4133	4305	4045	1192	1998	2193	4061	4666	2164
12	2000 Federal Report Surplus Deficit	4518	3599	288	-695	1470	2608	2443	2159	2240	2020	2156	2332	1828	1821	1888
13	2001 Federal Report Surplus Deficit	2183	-697	-287	-1192	-597	-699	-1054	-948	-930	-1149	-2211	257	363	-408	-536
14	2002 Federal Report Surplus Deficit	462	-750	-668	-1640	-968	-1225	-549	-25.6	-497	397	1993	2178	4033	3724	448
15	2003 Federal Report Surplus Deficit	904	45.7	-195	-1214	-140	-883	-363	-1345	1034	768	1105	1649	3292	-157	261
16	2004 Federal Report Surplus Deficit	-575	-930	-591	-1162	-26.5	-308	87.0	-138	-328	-42.7	-56.5	1243	2559	421	76.6
17	2005 Federal Report Surplus Deficit	-226	16.2	128	-564	183	1214	928	893	291	-930	-926	1454	2339	1341	598
18	2006 Federal Report Surplus Deficit	463	-684	-359	-995	-156	872	3118	3523	942	3088	1663	3584	3977	1930	1541
19	2007 Federal Report Surplus Deficit	546	-649	-489	-1070	-530	1148	2335	2027	2565	1851	801	1882	2847	1533	1121
20	2008 Federal Report Surplus Deficit	343	-826	-643	-915	-60.7	341	133	312	38.5	-427	-1127	2239	4611	3004	670
21	2009 Federal Report Surplus Deficit	1431	1410	-30.3	-962	-620	-191	1713	-29.5	-107	1668	922	1841	2468	-231	549
22	2010 Federal Report Surplus Deficit	-153	-1150	-426	-1045	-219	-672	-203	-1508	-1179	-825	-1433	338	3941	1770	-78.5
23	2011 Federal Report Surplus Deficit	879	-97.8	-33.5	-1072	-610	972	4196	4877	2681	3903	659	2640	5093	5237	2203
24	2012 Federal Report Surplus Deficit	4061	1884	9.12	-1137	-466	743	2355	2190	2531	3319	3263	3106	4661	4871	2092
25	2013 Federal Report Surplus Deficit	3353	2189	-113	-889	141	2757	1086	255	484	2920	1444	2449	3511	2180	1409
26	2014 Federal Report Surplus Deficit	1261	-222	69.9	-1142	-313	-36.0	1699	-183	3035	2762	1275	2435	3808	3014	1251
27	2015 Federal Report Surplus Deficit	1315	-152	9.55	-1113	277	2043	3289	3592	4314	1334	-510	444	748	-1139	1107
28	2016 Federal Report Surplus Deficit	-61.9	-920	-743	-934	-773	81.6	847	361	2197	2389	2229	2543	1918	-728	548
29	2017 Federal Report Surplus Deficit	-139	-871	-305	-448	2065	802	3423	3994	5561	4360	3161	3737	4597	1861	2362
30	2018 Federal Report Surplus Deficit	1787	298	-331	-1035	-1047	90.1	3624	4850	2734	2500	1521	3959	4021	1235	1741

SECTION 5: PACIFIC NORTHWEST REGIONAL ANALYSIS EXHIBITS

Exhibit 5-1: Annual Energy – PNW Regional Surplus/ Deficit: Operating Years 2026 – 2035, Firm Water Conditions

Loads and Resources - Pacific Northwest Region Percentile
Operating Year: 2026 to 2035 Percentile: 10
White Book 2025 (Energy Only) Report Date: **4/17/2025**
S268-WB-20250415-174748

	Energy-aMW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Regional Loads										
1	**Retail Loads**	25380	25871	26382	26944	27481	28059	28496	28883	29057	29203
2	Federal Agency	157	161	164	170	174	177	178	181	183	185
3	USBR	192	192	194	197	197	197	197	197	197	197
4	Cooperative	3624	3948	4336	4724	5124	5560	5875	6109	6171	6212
5	Municipality	2582	2597	2613	2629	2648	2666	2675	2682	2687	2693
6	Public Utility District	5158	5249	5293	5359	5424	5491	5551	5620	5670	5709
7	Investor-Owned Utility	13617	13673	13730	13813	13864	13917	13968	14042	14096	14154
8	Direct-Service Industry	51.3	51.3	51.3	51.3	51.3	51.3	51.3	51.3	51.3	51.3
9	Federal Diversity	0	0	0	0	0	0	0	0	0	0
10	**Exports**	814	800	800	798	769	468	373	373	373	373
11	Canada	319	317	318	317	290	237	237	237	238	237
12	East Continental Divide	3.33	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
13	Pacific Southwest	491	482	481	479	477	230	134	135	135	135
14	**Total Regional Loads**	**26194**	**26671**	**27182**	**27742**	**28250**	**28526**	**28869**	**29255**	**29430**	**29575**
	Regional Resources										
15	**Hydro**	12013	11971	12005	11991	12085	12056	12094	12130	12048	12235
16	Regulated Hydro - Net	10848	10813	10839	10834	10904	10884	10914	10938	10868	11036
17	Independent Hydro - Net	922	914	923	913	938	928	937	948	937	955
18	Small Hydro - Net	244	244	243	244	244	244	243	244	244	244
19	**Non-Hydro Renewable**	2907	2907	2906	2908	2907	2891	2902	2907	2907	2907
20	Wind - Net	2240	2240	2238	2240	2240	2224	2235	2240	2240	2240
21	Solar - Net	510	510	510	510	510	510	510	510	510	510
22	Other - Net	157	157	158	158	157	157	157	157	157	157
23	**Thermal**	12444	12176	12198	12103	12280	12029	12198	12158	12195	12090
24	Nuclear - Net	1116	994	1116	994	1116	994	1116	994	1116	994
25	Coal - Net	3201	3049	2955	2981	3034	2948	2962	3034	2948	2966
26	Natural Gas - Net	5371	5371	5373	5372	5368	5371	5372	5371	5371	5371
27	Petroleum - Net	0	0	0	0	0	0	0	0	0	0
28	Biofuel - Net	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5
29	Cogeneration - Net	2730	2737	2729	2730	2737	2691	2722	2734	2734	2734
30	**Imports**	597	600	605	609	613	132	38.7	38.8	38.9	39.0
31	Canada	38.8	38.8	38.8	38.8	38.8	36.7	36.5	36.4	36.4	36.4
32	Inland Southwest	509	513	517	521	525	93.6	0	0	0	0
33	Pacific Southwest	48.6	48.7	48.9	49.2	49.2	2.15	2.25	2.35	2.48	2.59
34	**Reserves & Losses**	-806	-798	-799	-796	-804	-782	-785	-786	-784	-787
35	Operating Reserves	0	0	0	0	0	0	0	0	0	0
36	Balancing Reserves	0	0	0	0	0	0	0	0	0	0
37	Transmission Losses	-806	-798	-799	-796	-804	-782	-785	-786	-784	-787
38	**Total Regional Resources**	**27153**	**26857**	**26914**	**26814**	**27080**	**26326**	**26447**	**26447**	**26404**	**26484**
39	**Total Surplus/Deficit**	**960**	**186**	**-269**	**-928**	**-1169**	**-2200**	**-2422**	**-2808**	**-3026**	**-3091**

Exhibit 5-2: Monthly Energy – PNW Regional Surplus/ Deficit: Operating Year 2026, Firm Water Conditions

Loads and Resources - Pacific Northwest Region Percentile

Operating Year: 2026 Percentile: 10

White Book 2025 (Energy Only) Report Date: **4/16/2025**

S268-WB-20250415-174748

	Energy-aMW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
	Regional Loads															
1	**Retail Loads**	25467	25297	22727	23290	25177	28933	28409	27368	25206	23672	23672	23250	24863	26315	25380
2	Federal Agency	144	143	120	144	167	185	188	199	171	149	149	134	133	152	157
3	USBR	342	350	304	133	3.79	3.73	8.80	13.3	56.9	255	255	345	382	444	192
4	Cooperative	3415	3397	3104	3406	3601	4037	4023	3849	3639	3503	3503	3471	3642	3805	3624
5	Municipality	2379	2357	2241	2408	2698	3103	3123	2981	2729	2458	2458	2261	2253	2373	2582
6	Public Utility District	4854	4820	4468	4733	5302	6020	6008	5765	5268	4930	4930	4674	4851	5061	5158
7	Investor-Owned Utility	14284	14180	12441	12413	13352	15532	15006	14509	13291	12326	12326	12315	13552	14430	13617
8	Direct-Service Industry	50.2	50.1	50.9	51.8	52.2	51.9	52.3	52.0	51.5	51.9	51.9	50.4	50.1	50.1	51
9	Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Exports**	978	1190	969	642	777	665	498	623	671	959	863	901	948	1065	814
11	Canada	411	481	305	305	305	305	305	305	305	305	305	305	305	328	319
12	East Continental Divide	15.4	14.5	14.9	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	3.3
13	Pacific Southwest	552	695	649	336	471	359	192	317	365	653	557	595	642	736	491
14	**Total Regional Loads**	**26445**	**26487**	**23696**	**23932**	**25954**	**29597**	**28907**	**27992**	**25876**	**24631**	**24536**	**24152**	**25811**	**27380**	**26194**
	Regional Resources															
15	**Hydro**	11278	10148	10313	8946	12350	13126	14067	11686	12234	10785	9998	14753	14029	11502	12013
16	Regulated Hydro - Net	10070	8947	9277	8137	11049	12024	12958	10821	11258	9667	8715	13210	12472	10238	10848
17	Independent Hydro - Net	883	878	791	646	1172	976	986	733	815	838	1001	1140	1134	859	922
18	Small Hydro - Net	325	323	244	163	128	126	124	132	162	280	282	403	422	405	244
19	**Non-Hydro Renewable**	2411	3185	2867	2346	2933	2271	1454	2172	2525	4089	3558	3866	3942	3862	2907
20	Wind - Net	1593	2340	2162	1744	2430	1871	1047	1663	1897	3314	2802	3026	3049	2954	2240
21	Solar - Net	658	686	548	443	344	242	259	351	470	619	599	692	759	727	510
22	Other - Net	159	159	157	160	159	159	148	158	158	157	157	149	134	181	157
23	**Thermal**	13426	13433	13492	13523	13713	13218	13059	12992	12160	11440	9713	9373	11165	12644	12444
24	Nuclear - Net	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116
25	Coal - Net	3821	3822	3825	3826	3824	3201	3082	3081	3029	2170	1974	2467	3095	3078	3201
26	Natural Gas - Net	5585	5592	5654	5716	5851	5921	5914	5853	5804	5484	4427	3366	4262	5587	5371
27	Petroleum - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Biofuel - Net	23.6	23.6	25.4	26.7	27.0	24.6	24.3	24.4	27.0	25.4	25.4	27.2	25.0	25.8	26
29	Cogeneration - Net	2880	2880	2871	2838	2896	2955	2923	2918	2183	2644	2171	2398	2667	2837	2730
30	**Imports**	593	593	518	489	675	777	612	612	515	462	462	511	671	724	597
31	Canada	20.8	20.8	15.8	22.0	38.9	49.3	62.3	70.8	62.7	30.2	30.2	28.9	38.6	27.0	39
32	Inland Southwest	571	571	501	466	454	491	461	476	451	430	430	480	631	695	509
33	Pacific Southwest	1.34	1.34	1.34	1.48	182	236	88.9	64.8	1.48	1.48	1.48	1.48	1.48	1.48	49
34	**Reserves & Losses**	-842	-832	-769	-716	-840	-832	-826	-777	-776	-758	-672	-807	-906	-873	-806
35	Operating Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Balancing Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Transmission Losses	-842	-832	-769	-716	-840	-832	-826	-777	-776	-758	-672	-807	-906	-873	-806
38	**Total Regional Resources**	**26866**	**26527**	**26420**	**24589**	**28832**	**28560**	**28366**	**26684**	**26659**	**26019**	**23060**	**27697**	**28901**	**27858**	**27153**
39	**Total Surplus/Deficit**	**421**	**40**	**2,724**	**657**	**2,878**	**-1,038**	**-541**	**-1,308**	**782**	**1,388**	**-1,476**	**3,545**	**3,090**	**479**	**960**

Exhibit 5-3: 30-Water Year Conditions Monthly Energy – PNW Regional Surplus/ Deficit: Operating Year 2026

Regional Report Surplus Deficit By Water Year

Operating Year 2026

White Book 2025 (Energy Only) Report Date: **4/24/2025**

S268-WB-20250415-174748

	Energy-aMW - Surplus Deficit	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
1	1989 Regional Report Surplus Deficit	1025	2618	2079	1392	2754	500	92.0	386	1991	4596	6076	5617	5078	1750	2403
2	1990 Regional Report Surplus Deficit	1066	715	2725	1407	3915	4503	3099	5195	3092	5247	5582	5075	8764	7415	4274
3	1991 Regional Report Surplus Deficit	5054	4858	3251	910	7404	4229	4478	7462	4754	6239	3297	5625	7505	9185	5356
4	1992 Regional Report Surplus Deficit	6114	4319	2721	620	3047	-1096	-446	346	887	1378	-1048	3749	2277	-298	1432
5	1993 Regional Report Surplus Deficit	498	170	2112	603	2394	-1864	-2415	-3415	1004	3985	-1281	6952	5642	3771	1395
6	1994 Regional Report Surplus Deficit	2677	1302	3275	545	2255	-1478	-1267	-344	1493	1111	2282	3746	2995	556	1286
7	1995 Regional Report Surplus Deficit	601	-87.4	2649	774	2287	-63.7	1159	4294	4990	2795	218	4561	8333	5801	3027
8	1996 Regional Report Surplus Deficit	4134	2069	3568	2891	9125	9729	9123	11452	10744	7609	8168	7461	9480	9519	7811
9	1997 Regional Report Surplus Deficit	5761	3763	3946	1557	3663	4602	9648	10372	10504	8310	9265	9865	11066	10010	7376
10	1998 Regional Report Surplus Deficit	7013	6642	5870	5983	6362	2654	2956	4630	4143	3199	978	8526	9168	6168	5450
11	1999 Regional Report Surplus Deficit	5828	2940	3502	901	2801	3324	7135	7915	8339	5313	5709	6622	10257	10787	5941
12	2000 Regional Report Surplus Deficit	8831	7795	3931	2006	7054	5718	4121	4533	5278	7166	6169	5978	5365	4936	5326
13	2001 Regional Report Surplus Deficit	4312	961	2778	1038	1950	-1029	-2354	-1360	-325	413	-3560	1480	1562	386	435
14	2002 Regional Report Surplus Deficit	958	-36.5	1633	-21.3	2150	-1113	-572	814	722	4058	5318	5553	9154	8249	2638
15	2003 Regional Report Surplus Deficit	2676	1435	2992	576	2648	-1156	12.3	-1160	3461	4050	2942	4017	6885	885	2063
16	2004 Regional Report Surplus Deficit	-440	-270	2138	1439	3223	163	11.3	442	1187	3209	1236	3449	5476	2125	1789
17	2005 Regional Report Surplus Deficit	281	1513	3791	2092	3654	2954	1711	1923	2050	1196	-426	3796	4902	3281	2621
18	2006 Regional Report Surplus Deficit	1418	129	2503	1251	3011	2164	5971	6498	3283	8346	5055	8333	9064	4754	4499
19	2007 Regional Report Surplus Deficit	1835	448	2444	915	3886	2820	3595	3979	6776	6637	3106	5063	6249	4073	3808
20	2008 Regional Report Surplus Deficit	1514	150	2657	1397	2839	1464	-286	966	1394	1380	-1566	6752	9954	7400	2944
21	2009 Regional Report Surplus Deficit	3664	3639	3082	1144	2535	-153	2735	468	945	5379	3166	5344	6506	1336	2658
22	2010 Regional Report Surplus Deficit	715	-265	2369	1189	3289	-624	108	-1815	-363	1281	-1508	1814	9201	5210	1714
23	2011 Regional Report Surplus Deficit	2514	1632	3232	1178	2624	2513	7337	8489	6797	10228	3437	7148	11360	11851	5930
24	2012 Regional Report Surplus Deficit	8424	5171	3610	1183	2731	1645	3891	4532	5982	8954	8253	7602	9879	10551	5581
25	2013 Regional Report Surplus Deficit	6390	5063	3256	1600	4242	5289	1384	924	2332	8275	3875	6240	7535	5166	4160
26	2014 Regional Report Surplus Deficit	2651	1160	3522	1226	2596	84.1	2663	588	6891	7415	4045	6381	7984	7262	3916
27	2015 Regional Report Surplus Deficit	3003	1307	3162	1298	4315	4592	5621	7177	8560	5436	-103	1074	1741	-1032	3416
28	2016 Regional Report Surplus Deficit	76.4	-343	2522	1110	2460	1339	1679	2084	5635	7326	5848	5752	3992	139	2756
29	2017 Regional Report Surplus Deficit	373	-31.7	2428	3210	7488	1801	4749	7944	11776	11183	7696	8847	10148	4815	6037
30	2018 Regional Report Surplus Deficit	4175	2015	2761	1528	2585	1095	6034	8666	6195	7782	5463	8600	8209	3808	4898

APPENDIX – REPORTS AVAILABLE UPON REQUEST

Please send request via email to WhtieBook@bpa.gov, and allow three to five business days for turn-around time.

A. Annual Energy (aMW) – Operating Years 2026 – 2035
B. Monthly Energy (aMW) – Operating Years 2026 – 2035

	Report #	
Report Descriptions	**Annual**	**Monthly**
Federal Report Surplus/ Deficit	1A	1B
Regional Report Surplus/ Deficit	2A	2B
Regional Total Retail Load	3A	3B
Regional Exports	4A	4B
Regional Imports	5A	5B
Regional Intra-Regional Transfer	6A	6B
BPA Sales to Preference and Legacy Customers	7A	7B
Regional Regulated Hydro	8A	8B
Regional Independent Hydro	9A	9B
Regional Small Hydro	10A	10B
Regional Non-Hydro Renewable – Wind	11A	11B
Regional Non-Hydro Renewable – Solar	12A	12B
Regional Non-Hydro Renewable – Other	13A	13B
Regional Thermal – Nuclear	14A	14B
Regional Thermal – Coal	15A	15B
Regional Thermal – Natural Gas	16A	16B
Regional Thermal – Petroleum	17A	17B
Regional Thermal – Biofuel	18A	18B
Regional Thermal – Cogeneration	19A	19B
Non-Federal CER Deliveries to BPA	20A	20B
Federal Report Surplus/ Deficit by 30 Water Year	--	21B
Regional Report Surplus/ Deficit by 30 Water Year	--	22B



BONNEVILLE POWER ADMINISTRATION
DOE/BP-5429 ▪ May 2025

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-122:
Energy Reliability and Resilience

The Wayback Machine - https://web.archive.org/web/20251021071021/https://www.energy.gov/eere/energy-reliability-and-resilience
An official website of the United States government Here's how you know

U.S. DEPARTMENT of ENERGY

Energy Reliability and Resilience



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Energy reliability is the ability of a power system to consistently deliver power to homes, buildings, and devices—even in the face of instability, uncontrolled events, cascading failures, or unanticipated loss of system components. Energy resilience is the ability of the grid, buildings, and communities to withstand and rapidly recover from power outages and continue operating with electricity, heating, cooling, ventilation, and other energy-dependent services. Energy resilience increases energy reliability and renewable energy sources can help support a resilient, reliable energy system.

Resilient, reliable energy is critical to the well-being of every American. It keeps life-saving hospital equipment and communications systems operating, buildings at safe temperatures with good ventilation, and American workers to go about their business without interruption. Energy infrastructure—facilities or equipment used to generate, deliver, process, or produce energy—that can withstand and quickly recover from disruptions is resilient and reliable infrastructure.

A resilient and reliable power system reduces the likelihood of long-duration outages over large service areas, limits the scope and impact of outages when they do occur, and rapidly restores power after an outage.

What Makes Energy Resilient?

Power outages can be caused by extreme weather, breaches in cybersecurity, high energy demand that overloads the electric grid, failure of aging equipment, and physical interference with equipment. Grid disturbances are changes in electrical voltage and frequency on the grid that can lead to power outages.

A resilient electric grid distribution system uses local resources, such as solar panels and battery storage in homes and buildings, to quickly reconfigure power flows and recover electricity services during a disturbance. The approach to modernize the grid and increase resilience focuses on integrating distributed energy resources, advanced controls, grid architecture, and emerging grid technologies at a regional scale.

Strong resilience measures in building energy codes can also ensure that new construction and major renovation projects minimize energy use, maximize comfort, and enhance potentially life-saving resilience benefits. Building owners and operators, communities, and local and state governments can strategically plan to increase resilience using these resources.

What Makes Energy Reliable?

When we diversify our energy mix by adding more types of energy to the grid, we increase our energy reliability. The rise of renewable power, which comes from unlimited energy resources, like wind, sunlight, water, and the Earth's natural heat, has the potential to vastly improve the reliability of the American energy system. Currently, renewable energy generates about 21% of all U.S. electricity, and that percentage is rising quickly.

A reliable electric grid distribution system can continue to deliver electricity to homes and buildings regardless of any disruptions or disturbances. The approach to modernizing the grid to increase resilience and reliability focuses on integrating distributed energy resources, advanced controls, grid architecture, and emerging grid technologies at a regional scale. DOE efforts, like the Energy Storage Grand Challenge Roadmap, will increase resilience. DOE's Grid Modernization Initiative works with public and private partners to develop concepts, tools, and technologies needed to measure, analyze, predict, protect, and control the grid of the future.

Improving Reliability Through Energy Storage

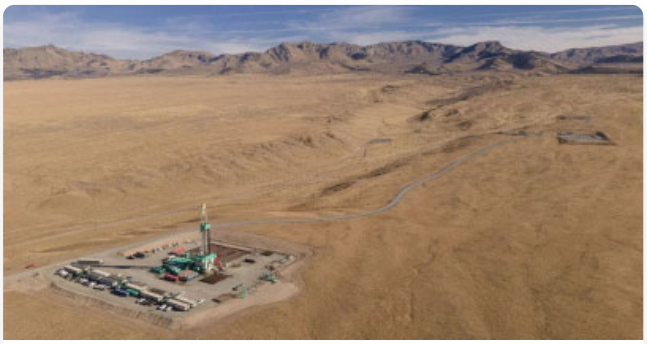
Energy storage technologies can improve energy reliability by making surplus energy available whenever it is needed, such as during a power outage.

Pumped storage hydropower is responsible for most U.S. commercial energy storage capacity and has been used for more than 100 years. Wind energy and solar energy can be captured and stored for later use with batteries, and researchers are investigating geothermal energy storage.

Energy storage is also essential to efficient transportation. EERE invests in research and development of hydrogen storage and batteries to ensure on- and off-road vehicles can reliably move people and goods from one place to another.

The U.S. Department of Energy's Energy Storage Grand Challenge is a comprehensive program to accelerate the development, commercialization, and use of next-generation energy storage technologies. As part of this program, the Long Duration Storage Shot™ aims to, within the decade, reduce the cost of grid-scale energy storage by 90% for systems that can provide energy for at least 10 hours in duration.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-123:
NERC 2024 Long-Term Reliability Assessment

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2024 Long-Term Reliability Assessment

December 2024

Corrected July 11, 2025



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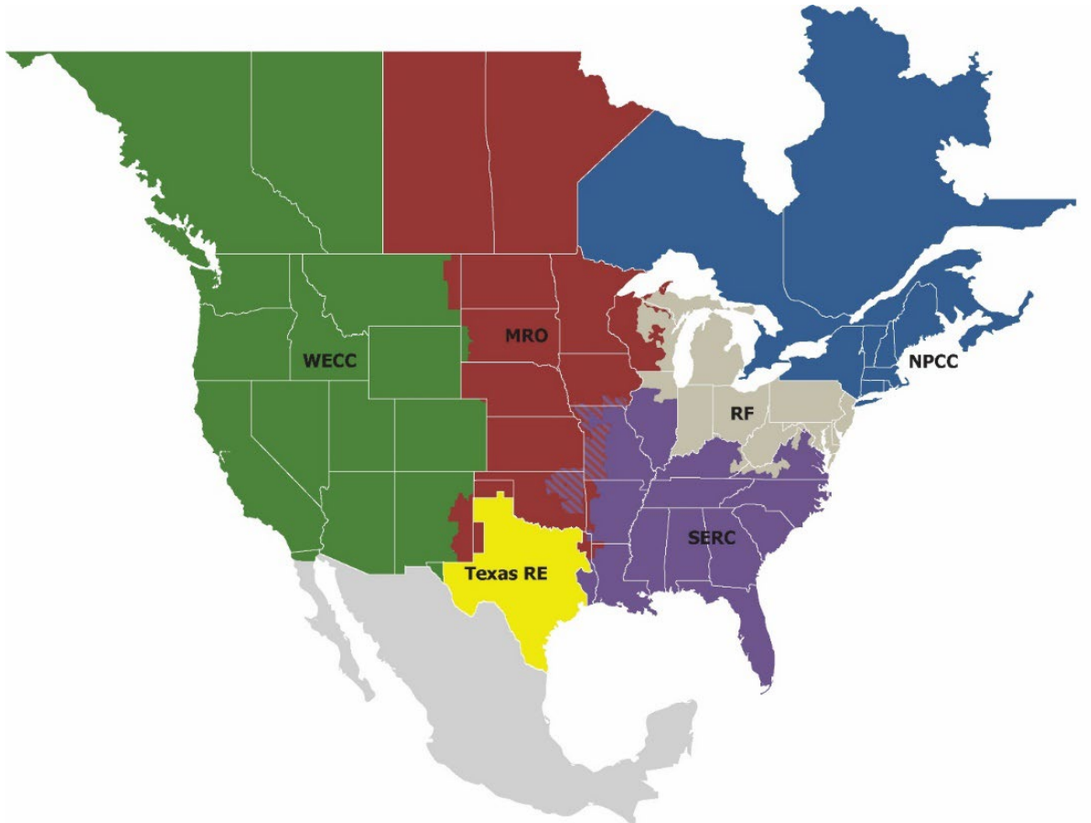
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area basis (see **Regional Assessments Dashboards**) to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer-review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts; this peer-review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees subsequently accepted this assessment and endorsed the key findings.

NERC develops the *Long-Term Reliability Assessment* (LTRA) annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations;[3] this is also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2024 about known system changes with updates incorporated prior to publication. This *2024 LTRA* assessment period includes projections for 2025–2034; however, some figures and tables examine data and information for the 2024 year. NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the **Demand Assumptions and Resource Categories** section of this report. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment; it is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through NERC's Electricity Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electric industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policymakers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

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[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the How NERC Defines BPS Reliability section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

[5] ERO Reliability Assessment Process Document

Assumptions

In this *2024 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2024. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading this Report

This report is compiled into two major parts:

1. **A reliability assessment of the North American BPS with the following goals:**
   a. Evaluate industry preparations that are in place to meet projections and maintain reliability
   b. Identify trends in demand, supply, reserve margins, and probabilistic resource adequacy metrics
   c. Identify emerging reliability issues
   d. Focus the industry, policymakers, and the general public's attention on BPS reliability issues
   e. Make recommendations based on an independent NERC reliability assessment process
2. **A regional reliability assessment that contains the following:**
   a. A 10-year data dashboard
   b. Summary assessments for each assessment area
   c. A focus on specific issues identified through industry data and emerging issues
   d. A description of regional planning processes and methods used to ensure reliability

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

In the *2024 LTRA*, NERC finds that most of the North American BPS faces mounting resource adequacy challenges over the next 10 years as surging demand growth continues and thermal generators announce plans for retirement. New solar PV, battery, and hybrid resources continue to flood interconnection queues, but completion rates are lagging behind the need for new generation. Furthermore, the performance of these replacement resources is more variable and weather-dependent than the generators they are replacing. As a result, less overall capacity (dispatchable capacity in particular) is being added to the system than what was projected and needed to meet future demand. **The trends point to critical reliability challenges facing the industry: satisfying escalating energy growth, managing generator retirements, and accelerating resource and transmission development.**

This *2024 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next 10 years; it also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS. The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors. Summaries of the report sections are provided below.

Capacity and Energy Risk Assessment

The **Capacity and Energy Risk Assessment** section of this report identifies potential future electricity supply shortfalls under normal and extreme weather conditions. NERC's evaluation of resource adequacy in the LTRA considers both the capacity of the resources and the capability of resources to convert inputs (e.g., fuel, wind, and solar irradiance) into electrical energy. NERC used both a probabilistic assessment and a reserve margin analysis to assess the risk of future electricity supply shortfalls. Both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development.

Areas categorized as **High Risk** fall below established resource adequacy criteria in the next five years. High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Extreme weather, producing wide-area heat waves or deep-freeze events, poses an even greater threat to reliability. **Elevated-Risk** areas meet resource adequacy criteria, but analysis indicates that extreme weather conditions are likely to cause a shortfall in area reserves. **Normal-Risk** areas are expected to have sufficient resources under a broad range of assessed conditions. The results of the risk assessment are depicted in **Figure 1**.

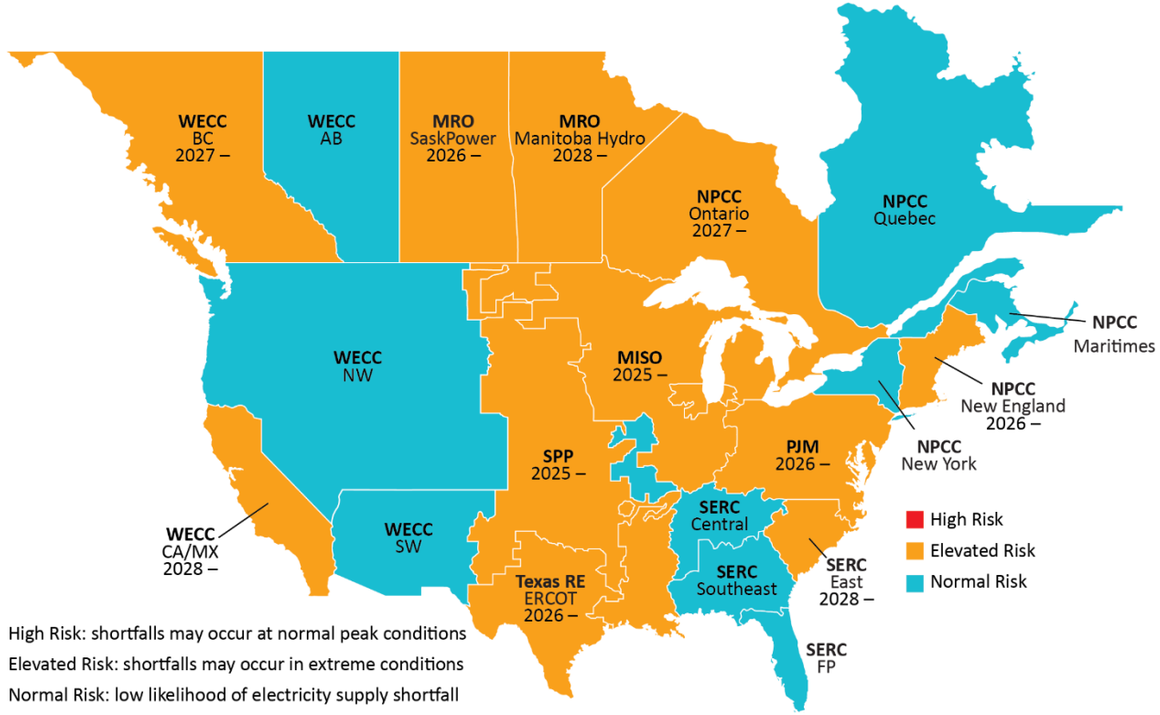


Figure 1: Risk Area Summary 2025–2029 (Corrected July 2025)

Regional Assessments Dashboards

The **Regional Assessments Dashboards** section contains dashboards and summaries for each of the 20 assessment areas, developed from data and narrative information collected by NERC from the six Regional Entities. Probabilistic Assessments (ProbA) are presented that identify energy risk periods and describe the contributing demand and resource factors.

Table 1: Capacity and Energy Risk Assessment Area Summary (Corrected June 2025)			
Area	**Risk Level**	**Years**	**Risk Summary**
MISO	Elevated	2025 -	Uncertainty around new resource additions and existing generator retirements results in resource adequacy risks. Above-normal generator outages during extreme weather can result in unserved energy or load loss.
Manitoba	Elevated	2028 -	Potential resource shortfalls in low-hydro conditions, driven by rising demand.
SaskPower	Elevated	2026 -	Risk of insufficient generation during fall and spring when more generators are off-line for maintenance.
Southwest Power Pool (SPP)	Elevated	2025 -	Potential energy shortfalls during peak summer and winter conditions arise from low wind conditions and natural gas fuel risk.
New England	Elevated	2026 -	Strong demand growth and persistent winter natural gas infrastructure limitations pose risks of supply shortfalls in extreme winter conditions.
Ontario	Elevated	2027 -	Reserve margins fall below RMLs as nuclear units undergo refurbishment and some current resource contracts expire. Demand growth is also adding to resource procurement needs.
PJM	Elevated	2026 -	Resource additions are not keeping up with generator retirements and demand growth. Winter seasons replace summer as the higher-risk periods due to generator performance and fuel supply issues.
SERC-East	Elevated	2028 -	Demand growth and planned generator retirements contribute to growing energy risks. Load is at risk in extreme winter conditions that cause demand to soar while supplies are threatened by generator performance, fuel issues, and inability to obtain emergency transfers.
ERCOT	Elevated	2026 -	Surging load growth is driving resource adequacy concerns as the share of dispatchable resources in the mix struggles to keep pace. Extreme winter weather has the potential to cause the most severe load-loss events.
California-Mexico	Elevated	2028 -	Demand growth and planned generator retirements can result in supply shortfalls during wide-area heat events that limit the supply of energy available for import.
British Columbia	Elevated	2027 -	Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighboring areas are unable to provide excess energy.

Risk from Additional Generator Retirements

Plans for generator retirements continue at similar pace and scale to levels reported in the *2023 LTRA*. Confirmed generator retirements (52 GW by 2029 and 78 GW over the 10-year period) are accounted for in the Capacity and Energy Risk Assessment above. Economic, policy, and regulatory factors spur further fossil-fired generators to retire in the 10-year horizon. Announced retirements, which include many generators that have not begun formal deactivation processes with planning entities, total 115 GW over the 10-year period. The effect of all retirements on the assessment area Planning Reserve Margins (PRM) can be seen in **Figure 2**. On-peak reserve margins fall below RMLs; the levels required by jurisdictional resource adequacy requirements) in the next 10 years in almost every assessment area, signaling an accelerating need for more resources.

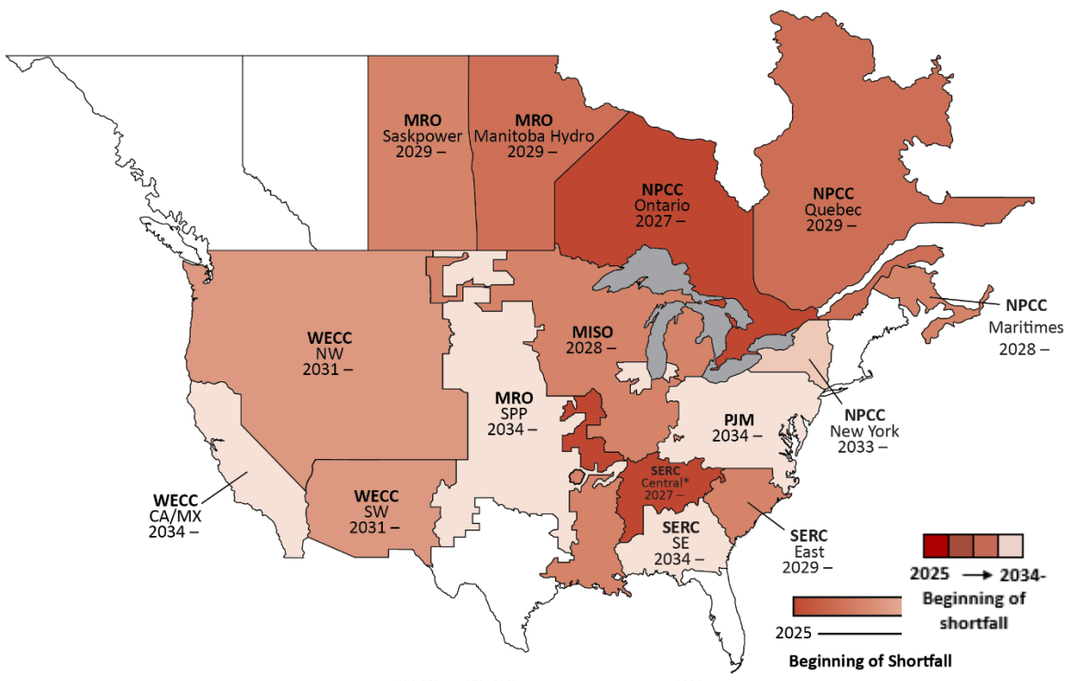


Figure 2: Projected Reserve Margin Shortfall Areas with Announced Generator Retirements (Corrected July 2025)

Changing Resource Mix and Reliability Implications

New resource additions continue at a rapid pace. Solar PV remains the overwhelmingly predominant generation type being added to the BPS followed by battery and hybrid resources, natural-gas-fired generators, and wind turbines. New resource additions fell short of industry's projections from the *2023 LTRA* with the notable exception of batteries, which added more nameplate capacity than was reported in development last year.

As older fossil-fired generators retire and are replaced by more solar PV and wind resources, the resource mix is becoming increasingly variable and weather-dependent. Solar PV, wind, and other variable energy resources (VER) contribute some fraction of their nameplate capacity output to serving demand based on the energy-producing inputs (e.g., solar irradiance, wind speed). The new resources also have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. As generators are deactivated and replaced by new types of resources, ERS must still be maintained for the grid to operate reliably.

Natural-gas-fired generators are a vital BPS resource. They provide ERSs by ramping up and down to balance a more variable resource mix and are a dispatchable electricity supply for winter and times when wind and solar resources are less capable of serving demand. Natural gas pipeline capacity additions over the past seven years are trending downward, and some areas could experience insufficient pipeline capacity for electric generation during peak periods.

Trends and Reliability Implications

Demand and transmission trends affect long-term reliability and the sufficiency of electricity supplies. A summary for each is provided below and further discussed within the **Demand Trends and Implications** and **Transmission Development and Interregional Transfer Capability** sections.

Demand Trends

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb; demand growth is now higher than at any point in the past two decades. Increasing amounts of large commercial and industrial loads are connecting rapidly to the BPS. The size and speed with which data centers (including crypto and AI) can be constructed and connect to the grid presents unique challenges for demand forecasting and planning for system behavior. Additionally, the continued adoption of electric vehicles and heat pumps is a substantial driver for demand around North America. The aggregated BPS-wide projections for both winter and summer have increased massively over the 10-year period:

- The aggregated assessment area summer peak demand forecast is expected to rise by 15% for the 10-year period: 132 GW this LTRA up from over 80 GW in the *2023 LTRA*.
- The aggregated assessment area winter peak demand forecast is expected to rise over almost 18% for the 10-year period: 149 GW this LTRA up from almost 92 GW in the *2023 LTRA*.

Transmission Trends

For the first time in recent years, transmission projections reported for the LTRA reflect a significant increase in transmission development. This year's cumulative level of 28,275 miles of transmission (>100 kV) in various stages of development for the next 10 years is substantially higher than the *2023 LTRA* 10-year projections (18,675 miles) and is above the average of the past five years of NERC's LTRA reporting on average (18,900 miles of transmission planning projects in each 10-year period published in the last five LTRAs). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning stages of development.

New transmission projects are being driven to support new generation and enhance reliability. Transmission development continues to be affected by siting and permitting challenges. Of the 1,160 projects that are under construction or in planning for the next 10 years, 68 projects totaling 1,230 miles of new transmission are delayed by siting and permitting issues, according to data collected for the LTRA. Questions of cost allocation and recovery can also challenge transmission development when the benefits apply to more than one area, as often occurs with projects that enhance interregional transfer capability.

In NERC's separate Interregional Transfer Capability Study (ITCS), which was performed to meet requirements contained in the Fiscal Responsibility Act of 2023, NERC found that an additional 35 GW of transfer capability across the United States would strengthen energy adequacy under extreme conditions. Increasing transfer capability between neighboring transmission systems has the potential to alleviate energy shortfalls in some areas identified in this LTRA's **Capacity and Energy Risk Assessment**. Conversely, when resource plans are developed that address these same energy shortfalls, such as through resource additions, demand-side management initiatives, or changes to generator retirement plans, the need for increased transfer capability will also change. Planners have options for reducing energy adequacy risks from extreme weather. Selecting the best course of action will depend on weighing these options against various engineering, economic, policy, reliability, and resilience objectives.

The ITCS provides foundational insights that facilitate stakeholder analysis and actions; it is not a transmission plan. In the future, NERC will extend the study beyond the congressional mandate to include transfer capabilities from the United States to Canada and among Canadian provinces.

Emerging Issues

The **Emerging Issues** section discusses developments and trends that have the potential to substantially change future long-term demand and resource projections, resource availability, and reliable operations of the BPS. Topics include data centers and large industrial loads, battery energy storage systems, electric vehicles and load, and energy drought. NERC's RSTC has formed new task forces where needed to address emerging issues.

Recommendations

To address the energy and capacity risks identified in this LTRA, NERC recommends the following priority actions:

1. **Integrated Resource Planners, market operators, and regulators: Carefully manage generator deactivations.** Independent System Operator/Regional Transmission Organizations (ISO/RTOs) should evaluate mechanisms and process enhancements for obtaining information on expected generator retirements that would support early identification of reliability risks. State and provincial regulators and ISO/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulatory and policy-setting organizations must use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be developed and placed in service.

2. **NERC and Regional Entities: Improve the LTRA by incorporating new analysis and criteria to inform stakeholders of future reliability risks.** NERC increased the frequency of the ProbA from biennial to annual and included unserved energy and load-loss metrics as the basis for risk analysis in this year's LTRA. To be more effective in using energy criteria and outputs of probabilistic analysis, NERC must specify consistent methods and assumptions for assessment areas to follow in preparing the annual ProbA. NERC and the Regional Entities, in consultation with the RSTC, should also continue to enhance NERC's LTRA to assess ERSs in the future system and the potential impact of new and evolving electricity market practices, regulations, or legislation on resource adequacy. Finally, NERC should work with the Regional Entities to perform wide-area energy analysis with modeled interregional transfer capability. Wide-area energy analysis will support the evaluation of extreme weather and regional fuel supply issues on an interconnection level.

3. **Regulators and Policymakers: Streamline siting and permitting processes to remove barriers to resource and transmission development.** As ISO/RTOs continue looking for opportunities to speed transmission planning processes, delays from siting and permitting activities will need to be reduced. These are the most common causes for delayed transmission projects. Support from regulators and policymakers at the federal, state, and provincial levels is urgently needed.

4. **Regulators, electric industry, and gas industry member organizations: Implement a framework for addressing the operating and planning needs of the interconnected natural gas-electric energy system.** Various initiatives were launched in the past year to address the reliability needs that arise from the complexity of interconnecting natural gas and electric infrastructure. Voluntary actions taken by the natural gas industry in response to the North American Energy Standards Board (NAESB) Forum report are a positive step toward improving winter readiness. The National Association of Regulatory Utility Commissioners (NARUC) launched its Gas-Electric Alignment for Reliability (GEAR) task force this year and recently created the Natural Gas Readiness Forum. For its part, NERC continues to collaborate extensively with industry and policymakers. NERC has enhanced its Reliability Standards requiring generators to prepare for winter extremes, implement training, and establish communication protocols between generators and grid operators. Current standards projects encompass extreme weather planning and energy assurance requirements. NERC will continue to provide full support to initiatives aimed at achieving a reliable interconnected energy system and urges regulators and policymakers to support needed avenues of coordination between the two sectors.

5. **Regional transmission organizations, independent system operators, and FERC: Continue to ensure essential reliability services are maintained.** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate ERSs.[7] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to ERSs. As replacement resources are interconnected, these new resources should be capable of supporting voltage, frequency, ramping, and dispatchability. Many technologies can contribute to ERSs, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are provided and maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue.

In addition to these priorities, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. All recommendations are listed in the **Recommendations and ERO Actions Summary** section.

[7] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

Capacity and Energy Assessment

The resource mix transformation is making traditional capacity-based adequacy criteria obsolete. Resource Planners and state and provincial policymakers use resource adequacy criteria to ensure sufficient resources are available to meet demand. In their application, current capacity-based adequacy criteria were not designed to differentiate between the scenarios, size, frequency, duration, and timing of energy shortfalls. This has become increasingly important as the resource transformation evolves from capacity-based resources with assured and stored energy supplies to energy-constrained resources that are increasingly impacted by weather and environmental conditions. Therefore, supplemental criteria must be adapted to properly assess system adequacy and help determine appropriate solutions. This year's LTRA includes probabilistic indices to measure these additional dimensions of risk and provide a more robust approach to understanding risk of inadequacy in future plans.

Assessment Approach

NERC is using two approaches in this LTRA to assess future resource capacity and energy risk; both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development:

- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over all hours. This approach identifies high-risk periods and potential energy constraints resulting in load-loss events. The 2024 ProbA is performed for each assessment area and examines the system as planned for the years 2026 and 2028. Loss-of-load hours (LOLH) and expected unserved energy (EUE) from NERC's ProbA are used to identify risk levels.
- Comparing the margin between projected resources and peak net demand, or reserve margin, to a reserve margin target (known as RML) that represents the accepted level of risk based on a probability-based loss-of-load analysis.

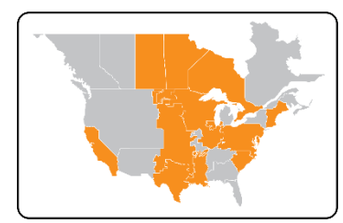
See the **Demand Assumptions and Resource Categories** for further details on these approaches. Assessment area dashboards (see **Regional Assessments Dashboards**) provide resource capacity and energy risk assessment results for all areas.

Risk Categories

An assessment area is **high risk** when established resource adequacy targets or requirements are not met during this assessment period. Regulatory authorities or market operators establish resource adequacy targets. Most targets in North America are currently based on a 1-day/event load loss in a 10-year planning requirement. See the **Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area**. Recently, regulators and policymakers in many states and market areas have begun considering or developing resource adequacy targets based on additional criteria that can better address energy risks and extreme weather-related supply disruption.[8] High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Unusual heat waves or deep-freeze events pose an even greater threat to reliability.

For the *2024 LTRA*, assessment areas are classified as high risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH exceeds 2.4 hours/year for one or more years in the ProbA.
- Annual normalized EUE exceeds 0.002% (20 ppm) for one or more years in the ProbA.
- Resource adequacy target(s) established by regulatory authority or market operator are not met.

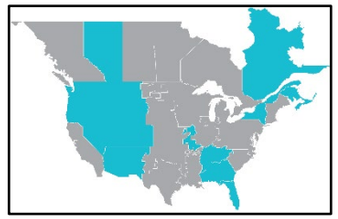


An assessment area is considered an **elevated risk** when it meets the established resource adequacy target or requirement, but probabilistic or deterministic analysis of conditions that are plausible but more extreme than normal seasonal peaks are likely to cause shortfall in area reserves. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, and/or disruption of normal electricity transfers. In the analysis, elevated risk may be found by modeling above-normal demand and low resource availability. The risk can also be identified by examining output data from probabilistic analysis tools to determine the underlying conditions for load-loss events. Simply put, elevated-risk areas meet resource adequacy requirements but may face challenges meeting load under extreme conditions. For the *2024 LTRA*, assessment areas are classified as elevated risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH is between 0.1 and 2.4 hours/year for one or more years in the ProbA.

[8] See the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid*.

- Annual normalized EUE is less than 0.002% (20 ppm) but non-zero for one or more years in the ProbA.
- Resource adequacy target(s) established by regulatory authority or market operator are met, but plausible scenarios of above-normal demand and/or low-resource conditions associated with a once-per-decade event indicate risk of load loss.



NERC assesses areas as **normal risk** when resource adequacy criteria are met and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). Although areas categorized as normal risk are expected to have sufficient resources for plausible extreme[9] conditions, they are not immune to the effects of high-impact, low-frequency weather events that affect demand and generation simultaneously. For the *2024 LTRA*, assessment areas are classified as normal risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH is below 0.1 hours/year.
- Annual normalized EUE is negligible or zero.
- Resource adequacy target(s) established by regulatory authority or market operator are met and reserves are expected to be available in plausible scenarios of above normal demand and/or low resource conditions associated with a once-per-decade event indicate risk of load loss.

Application of the Risk Criteria: NERC uses industry-provided demand and resource information and the results from probabilistic assessments performed by NERC Regional Entities, ISO/RTOs, and regulated utilities to determine risk of energy and capacity shortfalls. The methods, assumptions, and approaches used by entities to perform probabilistic assessments affect the results and outputs. In this year's LTRA, NERC incorporated new probabilistic assessment criteria (LOLH and EUE) from the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid* alongside established reserve margin criteria. In instances where an assessment area's probabilistic assessment results and reserve margins give mixed indications as to the risk category, adherence to resource adequacy targets (e.g., required RML and load-loss criteria) established by regulatory jurisdictions took precedence. Any other apparent contradictions with metrics and criteria were generally assessed according to results of all-hours probabilistic analysis.

Elevated-Risk Area Details

The below areas are projected to meet resource adequacy criteria and have energy and capacity for normal forecasted conditions but are at risk of supply shortfall in extreme conditions. Areas are listed in order of appearance in the **Regional Assessments Dashboards** section.

MISO

MISO has experienced slower resource additions due to market pressures and constraints faced by projects with signed interconnection agreements. MISO has highlighted uncertainties with a large number of new resources that have signed interconnection agreements (Tier 1 additions) and are expected to come on-line in the next several years.[10] Resource adequacy risks could grow over time absent the new capacity reflected in the Tier 1 additions and the deferral of announced retirements (see **Risk from Additional Generator Retirements**).

PRMs in MISO with resource additions are shown in **Figure 3** and **Figure 4**. MISO reports 56 GW of nameplate generating capacity, predominantly solar and batteries, with signed generation interconnection agreements (qualifying as Tier 1 and reflected in the ARM in **Figure 3** and **Figure 4**) as of July 2024 that can help meet resource adequacy needs if connection is completed. If resource additions remain at or near historically average levels (approximately 2.3 GW/year average over the last 3 years), PRMs in MISO will fall below the RML reserve margin requirements much faster. Summer PRMs with average resource additions are shown in **Figure 3** as **Reserve Margin-Avg Addition**.

[9] Plausible extreme conditions considered by NERC in this assessment are similar to those experienced during Winter Storm Elliott, Winter Storm Uri, and the 2020 Western Wide Area Heat Dome.
[10] See results from the 2024 Organization of MISO States (OMS)-MISO Survey.

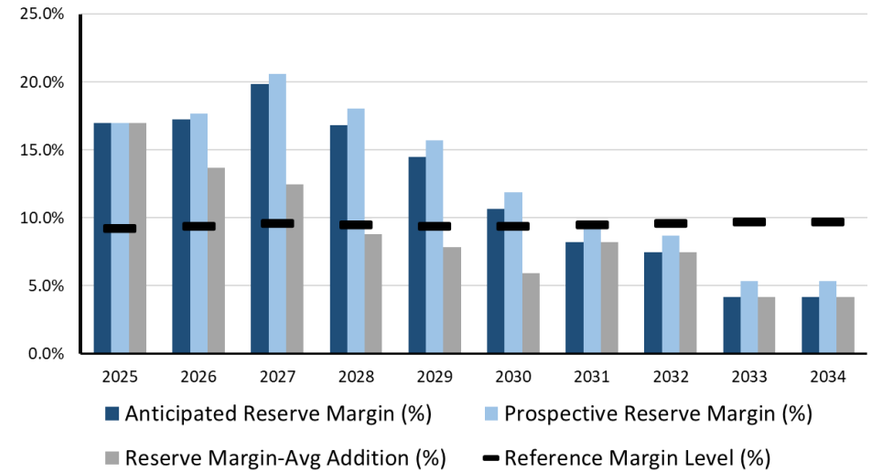


Figure 3: MISO Planning Reserve Margin–Summer

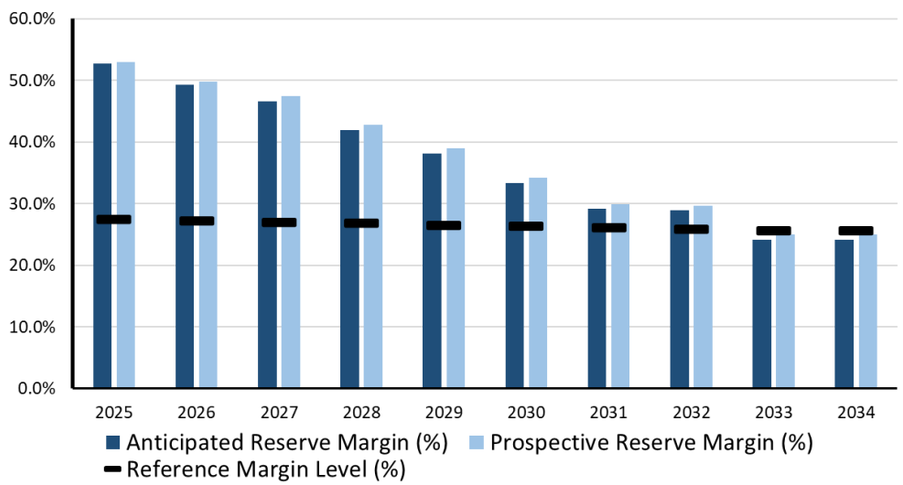


Figure 4: MISO Planning Reserve Margin–Winter

To establish the RMLs that define the minimum reserve margins for resource adequacy, MISO performs its annual probabilistic Loss-of-Load Expectation (LOLE) Study per MISO tariff. The study produces seasonal RMLs for the upcoming planning year that are used in MISO's planning resource auction. These RMLs are calculated such that they define the minimum PRM that will meet an LOLE of 1 day in 10 years. See the **MISO** assessment area pages.

MISO is an elevated risk in the *2024 LTRA* because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below RMLs within the next five years.

MRO-Manitoba Hydro

The electricity demand forecast in the province of Manitoba has increased since the *2023 LTRA*, driven by expected economic activity and adoption of electric vehicles. Resource projections have not changed significantly.

As in prior probabilistic assessments, Manitoba Hydro's 2024 ProbA indicates that there is some risk of load loss and unserved energy associated with very low hydro conditions (see **Table 2**). Electricity demand peaks in winter, making this the higher-risk season. However, electricity supplies could fall short during either peak summer or winter conditions should an extreme and prolonged drought affect hydro production.

Table 2: MRO-Manitoba Hydro ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	7.23	**4.71**	**68.87**
EUE (PPM)	0.29	**0.18**	**2.50**
LOLH (hours per year)	0.01	**0.06**	**0.91**
Operable On-Peak Margin	13.5%	**18.8%**	**15.6%**

** Year 2026 Results from the 2022 ProbA provided for trending*

MRO-SaskPower

Resource projections for Saskatchewan over the 10-year period have increased since the *2023 LTRA*, rising to just over 1 GW and include two new 377 MW gas-fired generation facilities, expansion of existing gas-fired generation facilities, and new geothermal resources. The peak demand forecast growth rate (1.35% annually) has changed little since the *2023 LTRA*.

The ProbA for SaskPower indicates there is some risk of load loss and unserved energy that diminishes with the new resource additions that are planned for 2027 (**Table 3**). Saskatchewan is a winter-peaking system; however, the unserved energy risks are more closely associated with the planned outages of large generators that typically occur in the fall and spring shoulder periods. The months of September and October are the highest risk periods because of the potential for high temperatures to unexpectedly extend beyond summer and into the maintenance period.

Table 3: MRO-SaskPower ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	117.0	**75.64**	**8.55**
EUE (PPM)	4.4	**2.81**	**0.30**
LOLH (hours per year)	0.9	**0.54**	**0.08**
Operable On-Peak Margin	24.6%	**24.8%**	**30.8%**

** Year 2026 Results from the 2022 ProbA provided for trending*

MRO-SPP

New resource capacity in the interconnection queue—primarily solar, battery, and wind—is currently projected to keep up with rising peak demand forecasts. DR programs are also increasing over the next 10 years. Resource adequacy issues can arise, however, if generators retire earlier than anticipated or new resource additions connect more slowly. Currently, there are over 8 GW of coal and gas-fired generators that have indicated that they may retire within the next 10 years, making the resource outlook unclear. SPP's summer reserve margins, based on installed generator capacity, remain above RMLs through 2029 (see **Figure 5**).

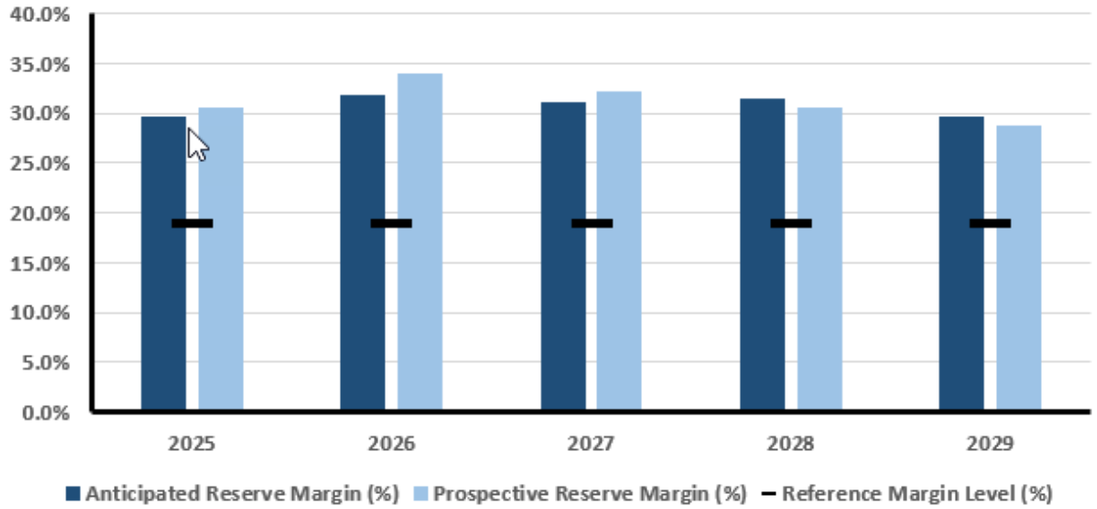


Figure 5: MRO-SPP Five-Year Planning Reserve Margin–Summer

All-hours probabilistic analysis performed by SPP shows that resource adequacy challenges are shifting from summer (when area demand is at its highest) to winter months (when the new resource mix is less capable of performing reliably). Annual results of the ProbA are in **Table 4** below. SPP's 2023 loss-of-load expectation (LOLE) study results indicate that a separate RML and seasonal resource capacity contributions are needed for the summer and winter seasons to effectively provide for resource adequacy.

Table 4: MRO-SPP ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.84	**0.00**	**6.61**
EUE (PPM)	0.00	**0.00**	**0.02**
LOLH (hours per year)	0.00	**0.00**	**0.01**
Operable On-Peak Margin	19.6%	**19.5%**	**16.0%**

** Year 2026 Results from the 2022 ProbA provided for trending*

NPCC-New England

New England is forecasting unprecedented demand growth driven by electrification of heating and transportation. Wind, solar, and batteries make up the projected resource additions, along with growth in distributed energy resources. Since the *2023 LTRA*, the peak demand forecast is relatively unchanged. New England has among the strongest winter demand forecast growth rates of any assessment area, rising over 7 GW in the 10-year period, or 35% from its current peak demand forecast.

The 2024 ProbA for NPCC-New England reveals increasing risk of load loss and unserved energy compared to the 2022 ProbA (see **Table 5**). Higher-demand forecast and replacement of dispatchable resources with more VERs contribute to this trend. In the ProbA modeling, supply shortfall risk is limited to the summer months and is associated with periods of above-normal demand and low resource output (e.g., low wind, solar, or high thermal outages).

Table 5: NPCC-New England ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.55	**10.69**	**67.40**
EUE (PPM)	0.00	**0.09**	**0.06**
LOLH (hours per year)	0.00	**0.07**	**0.03**
Operable On-Peak Margin	27.8%	**12.4%**	**13.7%**

** Year 2026 Results from the 2022 ProbA provided for trending*

While NPCC's ProbA results indicate that the risk of unserved energy in New England is concentrated in summer months, a persistent concern is whether there will be sufficient fuel available to satisfy electrical energy and operating reserve demands during an extended cold spell or a series of cold spells given the existing resource mix and regional fuel delivery infrastructure. Potential natural gas transportation constraints can affect supply to generators during extreme cold temperatures, when natural gas demand for space heating is also peaking. Most natural-gas-fired generators in the area do not have firm natural gas transportation service and can be subject to supply curtailment during peak conditions. Many natural-gas-fired generators in New England can also operate with stored oil, providing for assured electricity supply in extreme winter conditions while oil stores are procured and maintained. Scenarios of extended and extreme cold weather that affect the availability of natural gas and oil replenishments present a reliability risk but were not within the scope of the 2024 ProbA.

NPCC-Ontario

Near- and long-term resource adequacy challenges continue in the NPCC-Ontario assessment area as the Independent Electricity System Operator (IESO) manages lengthy refurbishment outages at nuclear generators and demand growth driven by agriculture and electrification. The beginning of projected shortfalls occurs in 2027 when some contracts for firm capacity are set to expire (see **Figure 6**). However, a number of resources with expiring contracts between 2026 and 2029 are anticipated to be re-committed for five-year terms through the IESO's second medium-term procurement, which is underway. As such, Ontario's Anticipated Reserve Margins (ARM) and Prospective Reserve Margins shown in **Figure 6** (which do not include this set of expiring resources) are conservative. Recommitment of these resources is expected to raise margins above the reference level in 2029 and help maintain reliability through the end of the decade. In May 2024, the IESO finalized long-term commitments for new-build battery storage facilities (1,784 MW) and new-build natural gas and biogas facilities (411 MW). Early operation incentives anticipated to bring a portion of these resources online as early as 2027 could help alleviate the reserve margin gap. The IESO also launched procurements for new capacity and energy-producing resources to be online as early as 2029. In addition, the IESO finalized an agreement with Hydro-Québec for capacity sharing in November 2024, providing 600 MW of firm imports to Ontario starting in Summer 2025 through Summer 2031. This capacity is also expected to help alleviate shortfalls indicated in 2027.

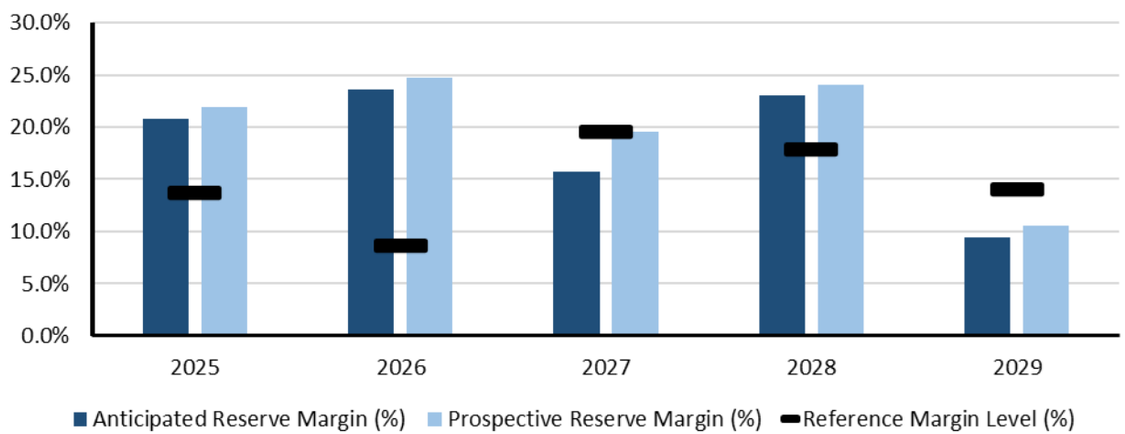


Figure 6: NPCC-Ontario Five-Year Planning Reserve Margin–Summer

The probabilistic assessment for Ontario performed by NPCC provides further insights into the potential for load loss and unserved energy. There is negligible risk of unserved energy and load loss in 2026 and earlier years; however, a small risk of load loss (< 0.01 hours) emerges after 2026 (Table 6). The 2024 ProbA study included only years 2026 and 2028, both of which have projected capacity surpluses above RMLs (see Figure 6). If 2027 and 2029 had been included in the ProbA, it can be expected that there would have been higher amounts of LOLH and unserved energy. ProbA results are also helped by the inclusion of electricity transfers from neighboring areas and modeling for some operating procedures used to manage supply shortfalls.

Table 6: NPCC-Ontario ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	72.16	**0.04**	**4.97**
EUE (PPM)	0.49	**0.00**	**0.03**
LOLH (hours per year)	0.44	**0.00**	**0.01**
Operable On-Peak Margin	-6.7%	**13.3%**	**9.5%**

** Year 2026 Results from the 2022 ProbA provided for trending*

PJM

PJM's projections for generator additions in 2025 and 2026 are scaled back dramatically from the *2023 LTRA* while demand forecasts continue to rise. As a result, ARMs for future years have fallen by as much as nine percentage points from last year. The trends in demand growth and resource additions create resource adequacy and system planning challenges for PJM as it carefully manages generator deactivation requests from the aging fossil and nuclear fleet.

PJM's ProbA results provide indication of the increasing resource adequacy risk to the system (see Table 7). EUE and LOLH are found in both ProbA assessment years (2026 and 2028) with risk concentrated in the winter months (especially January). The risk occurs on days where temperatures are very low across the entire PJM area, which results in high loads. While normal resource performance can meet these demand forecasts, resource performance from thermal resources on very cold days has historically been below normal due to freezing and fuel supply issues. Furthermore, solar resources are not likely to contribute during some of the coldest hours, resulting in very low total electricity supply and thus projections of load loss. ProbA analysis shows some summer load-loss and unserved energy risk but at much lower levels. Summer shortfall events are most likely to occur during wide-area heat events that coincide with low wind and low solar output, or very high outage and derates in the thermal generation.

Table 7: PJM ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.00	**537.52**	**1,043.44**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.12**	**0.22**
Operable On-Peak Margin	29%	**17.8%**	**17.7%**

** Year 2026 Results from the 2022 ProbA provided for trending*

SERC-East

The addition of solar resources is helping to raise summer on-peak reserve margins in the assessment area, despite rising demand forecasts and additional coal-fired generator retirements. Since the *2023 LTRA*, solar PV resources have grown from 1.5 GW to an expected 4.7 GW by the end of 2024. An additional 2 GW of solar PV resources are in the process of connecting. The summer peak demand forecast has also risen since the *2023 LTRA*, increasing by 2.8 GW (6.3%) over last year's projection. The area reserve margins have increased in the near term as a result of the solar resource additions then drop off after 2028 due to higher demand forecasts and planned generator retirements.

Despite these resource additions and higher summer reserve margins, the 2024 ProbA reveals growing resource adequacy risk in SERC-East (see Table 8). Measures of unserved energy and load-loss have increased since the 2022 ProbA as demand has risen and the resource mix has changed. SERC-East has changed from a summer-peaking area to one with peak electricity demand occurring in both the summer and winter seasons. This change is the result of added solar PV generation that shaves off summer peak demand and trends toward electrification in heating that drives up winter peak demand. The ProbA shows that the risk of unserved energy and load loss is concentrated in winter (January–February) months when wide-area extreme cold weather can affect electricity demand, generator performance, generator fuel supplies, and the availability of electricity imports. Based on current forecasts, resource adequacy risk will increase in SERC-East after 2028 due to the planned retirement of over 1,800 MW in coal-fired generation and continued load growth.

Table 8: SERC-East ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	92.49	**143.35**	**207.26**
EUE (PPM)	0.40	**0.60**	**0.81**
LOLH (hours per year)	0.08	**0.09**	**0.17**
Operable On-Peak Margin	16.1%	**14.2%**	**11.1%**

** Year 2026 Results from the 2022 ProbA provided for trending*

Texas RE-ERCOT

ERCOT is forecasting explosive demand growth, driven by data center projects, Bitcoin operations, development in oil- and natural-gas-producing areas, and industrial facilities. Over 20 GW of newly contracted large loads, in addition to other organic load growth, is projected to be added to ERCOT by 2028. Substantial amounts of solar PV and battery resources are being added to help meet rising demand, but there are significant reliability challenges to address during this period of rapid growth. Resource adequacy risks are mounting as fewer dispatchable resources comprise the resource mix. One of the strategies to address this risk is state implementation of a dispatchable resource generation loan program called the Texas Energy Fund. Furthermore, the forecasted growth in loads and resources poses significant challenges for transmission system planners.

Load growth and the characteristics of the resource mix are contributing to higher levels of unserved energy and load loss in probabilistic analysis (see **Table 9**). In the 2024 ProbA, EUE for the analyzed 2026 ERCOT system has risen to 19 ppm (0.0019 %) of the total annual supplied energy compared to the same analysis in the 2022 ProbA. The 2024 ProbA shows an improving trend in the analyzed 2028 ERCOT system, enabled by additional generation capacity from ERCOT scenarios developed to support rapid growth in large loads.[11]

A deeper analysis of the probabilistic assessment results reveals the unique characteristics of winter and summer risk. While peak winter loads can persist for 48 hours or longer, peak summer periods generally only last for a few hours. This is manifested in the duration and depth of the winter firm load-shed events that appear in the ProbA and has significant implications for the reliability contribution of energy-limited and non-dispatchable resources. The most extreme winter event modeled for 2026 was 16 hours in duration and up to 29 GW in load loss. In contrast, most summer unserved energy events were 1–2 hours in duration.

Table 9: Texas RE-ERCOT ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	1,235	**11,090**	**781**
EUE (PPM)	2.63	**18.95**	**1.12**
LOLH (hours per year)	0.30	**1.57**	**0.16**
Operable On-Peak Margin	35.9%	**28.8%**	**46.9%**

** Year 2026 Results from the 2022 ProbA provided for trending*

A key conclusion from the Texas RE-ERCOT 2024 ProbA is that matching the area's demand growth with a resource mix that is more variable and less fully dispatchable is increasing the risk of supply shortfalls that can result in load loss and unserved energy. When the seasonal characteristics of demand and resources are considered, Resource Planners can appropriately focus efforts to reduce the risk of potentially severe, long-duration winter shortfall events. The Public Utility Commission of Texas established a Reliability Standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude.

WECC-CA/MX

Resource additions continue to improve the overall resource adequacy outlook for the WECC California-Mexico assessment area. Since the 2022 ProbA, the planned extension of the Diablo Canyon nuclear plant (2.2 GW) and resource additions (over 5 GW nameplate in batteries, 3.3 GW nameplate in solar PV, and 0.2 GW in natural-gas-fired and geothermal generation) have alleviated supply shortfalls that were driving unserved energy and load-loss metrics in year 2026, as shown in the results of the 2024 ProbA performed by WECC (see **Table 10**).

Table 10: WECC-CA/MX ProbA Case Summary of Results

	2026*	2026	2028
EUE (MWh)	37,305	0	19,662
EUE (PPM)	136	0	70.07
LOLH (hours per year)	0.72	0	0.38
Operable On-Peak Margin	30.7%	43.2%	41.2%

** Year 2026 Results from the 2022 ProbA provided for trending*

Demand growth and planned generator retirements cause energy adequacy risks to re-emerge in future years. With a resource portfolio that includes a substantial amount of solar PV, the risk of supply shortfall is associated with summer evening periods when demand is high and solar output is diminished. WECC's analysis for the 2024 ProbA found only a small occurrence (<1 hour) of resources falling below margin levels for reliability in the 2028 study year. WECC further observed that load-loss and unserved energy risk was localized in the Mexico portion of the assessment area, reflecting localized resource and transmission system constraints.

[11] Due to the inclusion of an additional 20 GW of large loads based on newly signed interconnection agreements, study-year 2028 included additional generation capacity from the "High Large Load Adoption" scenario of the ERCOT 2024 Long-Term System Assessment (LTSA), which included 22 GW of combustions turbines (CT) and 4 GW of combined cycles (CC).

The CA/MX 2028 system analyzed by WECC for the 2024 ProbA reflects the continued rapid transformation of the power grid. The analysis assumes forecasted demand growth of 3.5 GW, substantial resource additions (4.6 GW of solar PV, 7.6 GW in batteries, and 0.8 GW of natural-gas-fired generation imported from repowered coal units in Utah), and the retirement of over 3 GW of gas-fired generation. As demand grows and the resource mix becomes increasingly variable, periods of supply shortfalls can emerge. Battery additions and transfers help make up for energy shortfalls that can arise during evening solar down ramps.

WECC-BC

BC has a predominantly hydroelectric generation system with vast amounts of energy storage provided by its reservoirs. Winter peak demand in the province is forecast to grow modestly over the next 10 years, from 11,966 MW this winter to 12,305 MW at the end of the 10-year period. Since the *2023 LTRA*, the winter peak demand compound annual growth rate (CAGR) has fallen from 1.0% to 0.3%. Growth rate and reserve margins are higher. While the overall resource adequacy outlook has improved, the 2024 ProbA indicates the area continues to be at an elevated risk of supply shortfall during extreme conditions. Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighboring areas are unable to provide excess energy.

Western Interconnection-wide probabilistic analysis performed by WECC for the 2024 ProbA reveals that risk of reserve shortages emerges after 2026, potentially resulting in unserved energy and load-loss events during extreme weather. WECC's analysis identified over five hours in 2028 when high demand and low supply from WECC-BC's internal resources were not able to be remedied with imports from neighboring areas experiencing similar conditions (see **Table 11**). In contrast, 2026 had no unserved energy or load-loss periods. An examination of hourly results showed that imports from neighbors were more available in 2026 to cover periods of potential shortfalls in BC Hydro's internal resources.

Table 11: WECC-BC ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	24	**0**	**103,132**
EUE (PPM)	0.71	**0**	**1,456**
LOLH (hours per year)	0.00	**0**	**5.52**
Operable On-Peak Margin	12.7%	**16.9%**	**9.4%**

** Year 2026 Results from the 2022 ProbA provided for trending*

WECC's interconnection-wide analysis simulates the probabilistic performance of resource types using historic hourly output data to identify future risk periods. Operators of systems with large hydroelectric storage facilities make adjustments to generation based on the level of demand and shape the water use within the day, week, month, or between years. These actions help posture hydroelectric generation for expected conditions and can reduce energy shortfall risks.

BC's supply margins relative to demand are lowest during winter peak demand periods. Imports from neighbors in the U.S. Northwest are common during these periods, and often during the overnight hours of 23:00 to 4:00 local. WECC's analysis shows the need for imports growing year to year throughout most of the LTRA forecast horizon. A widespread, extreme cold weather event in the Northwest that limits transfer capability is thus a risk to BC. Even though WECC-BC is expecting only moderate demand growth and relatively few retirements, diminished surplus capacity in neighboring areas is negatively affecting the resource adequacy outlook.

Normal-Risk Area Details

All other assessment areas (see **Figure 1**) are assessed as normal risk. In these areas, resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance).

Resource and Demand Projections

The **Capacity and Energy Assessment** section in this LTRA is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. Later sections in this report describe important trends in each of these forecast areas. The future electricity supply will come from a resource mix that is more variable, weather-dependent, and reliant on natural gas for fuel, requiring broad coordination and careful attention to manage reliability risks. Future electricity demand is being shaped by many factors that collectively influence peak demand forecast levels, peak seasons, and hourly profiles. Peak demand and energy forecasts are projected to continue rising dramatically over the *2024 LTRA* assessment period, exceeding their highest rates in recent years. Ongoing challenges with resource and transmission development and the continued pace of generator retirements raise concerns that, in the future, the risk assessment map will expand with more elevated and high-risk areas.

Risk from Additional Generator Retirements

Accelerated retirements of the existing coal, natural gas, and nuclear generators can have a profound and negative effect on the resource adequacy and reliability of the BPS in the next 10 years. In this preceding **Capacity and Energy Assessment** NERC accounted for nearly 79 GW of fossil-fired and nuclear generator retirements that are anticipated through 2034. Environmental regulations and energy policies have the potential to influence generators to seek deactivation during the 10-year assessment period.[12] An additional 43 GW of fossil-fired generators have announced plans to retire over the decade but have yet to enter deactivation processing with the planning authorities. These retirements, along with the confirmed retirements, contribute to declining reserve margins in the assessment areas over the next 10 years (see **Table 12**). As a result of demand growth and generator retirements, ARM is projected to fall below RML in 18 of the 20 assessment areas by 2034. While forecasts such as this factor into resource planning and market mechanisms to obtain resources needed for resource adequacy, it underscores the significant resource growth needed across North America. The lack of dispatchable resources and diverse generator fuel types in the interconnection processes makes the future resource mix look alarmingly unreliable. The potential for capacity and energy shortfalls and a higher-risk resource mix is heightened by economic and policy factors that place pressure on existing thermal generators.

The yearly projections of future retirements and an assessment area view are provided in the **Risk from** Additional Generator Retirements section.

[12] The Environmental Protection Agency (EPA) issued a final rule on May 9, 2024, establishing Greenhouse Gas Standards and Guidelines for Power Plants (the "GHG Rule"). This rule was released concurrently with three other EPA regulations that impact fossil-fueled power generation: Coal Combustion Residuals, Effluent Limitations Guidelines, and Mercury and Air Toxics Standards. Collectively, these four new regulations impose considerable financial and operational challenges on coal-fired generators.

Table 12: Anticipated Reserve Margins with Announced Retirements											
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MISO[13]	17.7%	10.3%	10.3%	13.2%	8.6%	7.1%	10.6%	8.2%	7.5%	4.2%	-2.5%
MRO-Manitoba	12.5%	21.3%	18.4%	18.0%	15.0%	9.8%	0.5%	-0.6%	-1.7%	-2.9%	-4.2%
MRO-SaskPower	28.9%	27.8%	26.6%	31.1%	29.4%	7.0%	28.8%	28.0%	26.7%	26.8%	1.2%
MRO-SPP	28.3%	26.7%	26.0%	25.0%	20.8%	19.1%	26.7%	24.9%	23.5%	22.4%	8.1%
NPCC-Maritimes	18.9%	20.6+%	25.5%	25.1%	18.6%	3.9%	23.4%	20.7%	19.1%	17.7%	-1.5%
NPCC-New England	20.4%	25.0%	25.0%	26.3%	24.9%	23.5%	22.0%	20.1%	19.7%	17.1%	14.6%
NPCC-New York	18.4%	17.1%	21.4%	22.5%	22.4%	21.6%	20.7%	18.3%	16.7%	14.9%	13.6%
NPCC-Ontario	22.5%	20.8%	23.6%	15.7%	23.0%	9.5%	5.1%	-0.2%	-1.4%	-3.9%	-5.5%
NPCC-Quebec	12.5%	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
PJM	29.8%	34.9%	35.7%	28.1%	21.4%	18.2%	23.1%	21.6%	20.1%	18.5%	10.3%
SERC-C	28.2%	18.9%	18.9%	15.0%	16.0%	15.2%	17.3%	17.1%	18.4%	21.1%	11.8%
SERC-E	30.4%	27.3%	25.8%	24.6%	20.6%	14.4%	14.3%	10.2%	6.3%	4.6%	-2.2%
SERC-FP	27.0%	25.4%	26.0%	23.2%	22.1%	20.9%	18.4%	22.0%	20.4%	18.2%	16.0%
SERC-SE	44.9%	39.9%	35.9%	31.5%	24.5%	21.4%	27.7%	25.8%	24.7%	23.7%	13.0%
TRE-ERCOT	24.3%	30.2%	32.5%	29.7%	25.6%	25.4%	27.8%	28.0%	28.4%	28.9%	24.9%
WECC-AB	36.3%	35.8%	35.7%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
WECC-BC	20.9%	25.2%	25.2%	15.8%	15.9%	22.3%	22.1%	21.6%	21.2%	13.4%	19.9%
WECC-CA/MX	38.6%	45.5%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25.0%	15.2%	11.1%
WECC-NW	34.5%	40.3%	38.9%	35.6%	30.7%	24.5%	18.3%	12.2%	10.2%	8.1%	5.9%
WECC-SW	28.6%	37.0%	35.6%	31.6%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-9.6%

Reducing Resource Capacity and Energy Risk

The risk of electricity supply shortfalls in the assessment period can be lowered through the concerted efforts of resource and system planning stakeholders. The actions taken in electricity markets and regulatory jurisdictions with the improving trends noted previously provide examples of what can work: obtaining additional firm resources to meet resource adequacy targets, delaying generation retirements when reliability needs dictate, and using capacity targets and energy risk metrics based on better resource and demand models. Specific and actionable recommendations are contained in the Executive Summary.

[13] MISO reserve margins in this table reflect MISO Seasonal Accredited Capacity for summer. Adjustments and derates are applied to account for factors affecting expected resource output, resulting in unforced capacity (UCAP) reserve margins that are lower compared to installed capacity (ICAP) values. For more information see the **MISO assessment area** page.

Resource Mix Changes

Capacity Versus Energy: Changes in the Way to Plan for Resource Adequacy

Industry's methods of planning for resource adequacy need to change. The modern power system requires the enhancement of assumptions and supplementation of risk information for a better characterization of the risk. Historically, the resource adequacy criterion has been based on the LOLE metric, which should be no more than 1 event-day in 10 years when the generating resources are less than load (commonly known as "1-day-in-10"). This has been a design basis for the U.S. electric grid for at least 70 years (with its first formal mention in a 1951 American Institute of Electrical Engineers paper by C. W. Watchorn) and has historically served the industry well. Two important related but separate discussion topics include considerations for assumptions in the calculation of LOLE and other metrics and the establishment of the resource adequacy criteria (i.e., traditionally in terms of LOLE-1-day-in-10). The 1-day-in-10 LOLE criterion is commonly converted into a minimum capacity requirement resulting in a target or RML. In doing this, planners determine the minimum PRM required to maintain a 1-day-in-10 LOLE level. Historically, systems with an actual PRM above the minimum generally have sufficient resources and provide adequate energy and ERSs that operators need to reliably operate the BPS. Issues can arise in resource adequacy planning processes when planners solely rely on the RML comparison as the system transforms from an era of certain to more uncertain fuel sources and load behavior. In recent years, NERC has documented warnings of potential energy shortages in its reliability assessments, while in many cases the RML comparison indicates no shortfall. Substantial uncertainty has been introduced into planning the system with the addition of energy-constrained resources (variable energy resources such as wind and solar, and, at times, just-in-time fuels such as natural gas) that are highly dependent on weather and environmental conditions. Uncertainty in energy sufficiency is increasing as the types of resources change, leaving fewer resources that can be dispatched (dispatchable resources) in response to the variable resource availability and greater exposure to constraints in fuel supplies, reservoir levels, or battery discharge capabilities. Historical generator reliability assumptions based on the idea of well-maintained, well-invested units with an anticipated long life are no longer adequate. This increases uncertainty as a greater proportion of fossil-fueled resources continue to be retired, often with little notice to system planners. Nameplate values of variable energy resources are not as meaningful as projected energy availability, and environmental conditions can adversely impact the simultaneous availability of thousands of megawatts.

Probabilistic analysis enhances deterministic transmission planning from an energy adequacy standpoint given the following factors:

- Considers likelihood of events: It uses historical data to estimate how often different outages and weather conditions might occur.
- Provides more information: It calculates the average impact of these events, including how often and how long power outages might last.
- Helps compare options: It enables the selection of the upgrade(s) that provide the best balance between cost and reliability over time to be chosen.

Detailed recommendations are included in a recently published NERC report:
Evolving Planning Criteria for a Sustainable Power Grid: A Workshop Report, June 2024

Changes in Existing BPS Resource Capacity

Thermal generator retirements and new resource additions continue at a rapid pace. Since the *2023 LTRA*, over 8 GW of coal-fired generation has been retired, while substantial solar and battery resources have connected to the grid (see **Table 13**). From a strictly on-peak capacity perspective, there has been little change (8,348 MW is 0.8% of the total BPS summer on-peak resource capacity.)

Table 13: Existing BPS Resource On-Peak Capacity

	2023 Capacity (MW)	2024 Capacity (MW)	Difference (MW)
Coal	188,856	180,402	-8,454
Petroleum	32,107	30,987	-1,120
Natural Gas	483,391	484,148	757
Biomass	7,273	7,381	108
Solar[14]	52,998	66,293	13,295
Wind[15]	32,320	31,370	-950
Geothermal	4,319	3,881	-438
Conventional Hydro	103,368	105,792	2,424
Run of River Hydro	1,565	2,047	482
Pumped Storage	19,463	19,422	-41
Nuclear	106,173	105,385	-788
Hybrid & Battery	5,593	9,909	4,316
Other	2,217	774	-1,443
Total	1,039,643	1,047,791	8,348

This year-on-year change in on-peak capacity continues the general trend of declining baseload and dispatchable generation—which includes coal-fired, natural gas, and nuclear generators—and rising VERs. **Figure 7** shows the trend continuing through 2034, where 20% of the generating capacity will be provided by VERs. Focusing on the relatively small change in total on-peak capacity since 2023 can mask risks to reliability that result when important attributes of the retiring generation resources are not inherent in the replacement resource mix. Thermal generation resources, such as coal-fired generators, have the capability to be dispatched when needed and provide system inertia, dynamic reactive support, and frequency response for stable grid operation. Most types of replacement resources have limited or none of these attributes. Further, retirements in the thermal generator fleet are making the resource mix less effective in meeting winter energy needs.

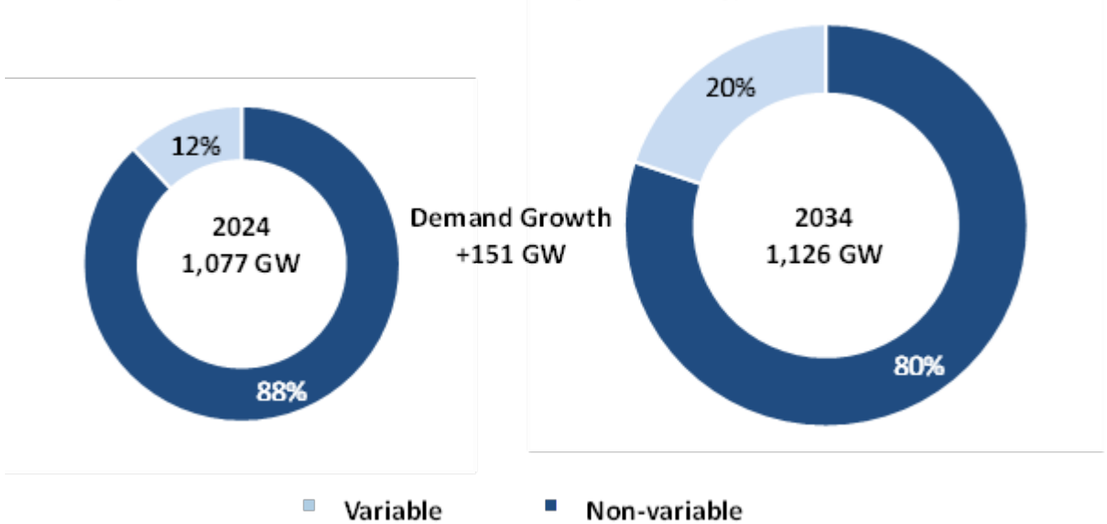


Figure 7: North America Total Generation Capacity in 2024 and 2034

Capacity Additions

New generation is added to the BPS through the area interconnection planning processes. Solar PV is the overwhelmingly predominant generation type being added to the BPS, followed by battery and natural-gas-fired generators, wind turbines, and hybrid resources. Batteries are now the second most predominant resource in the North America BPS interconnection queues. A summary of generation resources in the interconnection planning queues is shown in **Figure 8**.

Capacity in planning has grown since the *2023 LTRA* by over 44 GW (12%). In general, **Tier 1** resources are in the final stages for connection, while **Tier 2** resources are further from completion (see text box). Some projects that are in the earlier stages of the interconnection queue process will be withdrawn before completion due to supply chain issues, planning and siting challenges, and business or economic factors. While interconnection queues continue to swell, considerable uncertainty

[14] The capacity values in this table represent the on-peak contribution of solar resources. The total installed (nameplate) capacity of BPS solar in 2024 is 111,102 MW. See Table 11.
[15] The capacity values in this table represent the on-peak contribution of wind resources. The total installed (nameplate) capacity of BPS wind in 2024 is 176,636 MW. See Table 11.

surrounds the timing and amount of resource additions. (See an analysis of projected and actual additions on the next page).

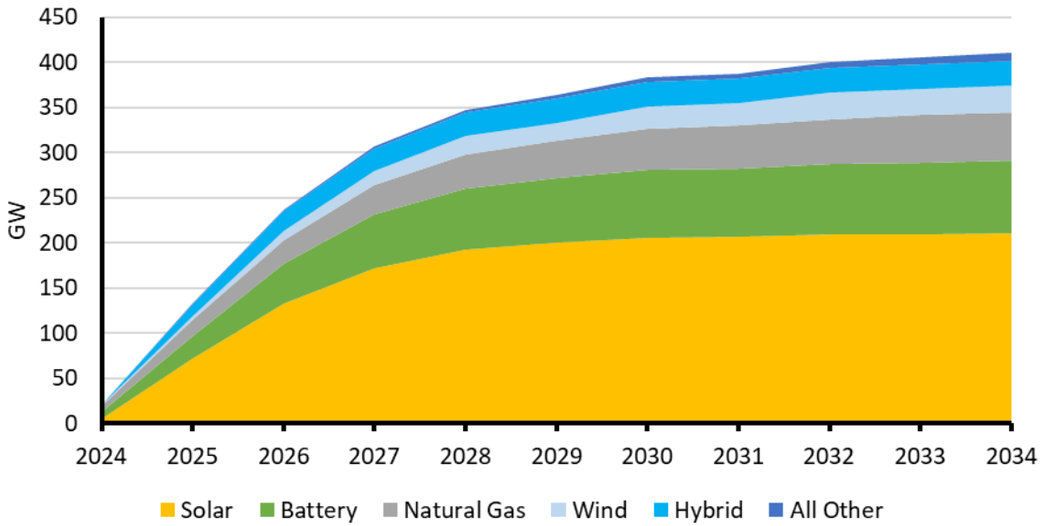


Figure 8: Tier 1 and 2 Planned Resources Projected Through 2034

Solar PV and wind nameplate capacity, both existing and planned, vary widely by area. Figure 9 and Figure 10 show current solar PV and wind installed capacities and the capacity in the planning process through 2034 for assessment areas with significant amounts. In addition, hybrid generation resources, which combine energy storage with a generating plant (i.e., a wind or solar farm), are connecting to the grid in parts of North America, and many more projects are in BPS planning processes.

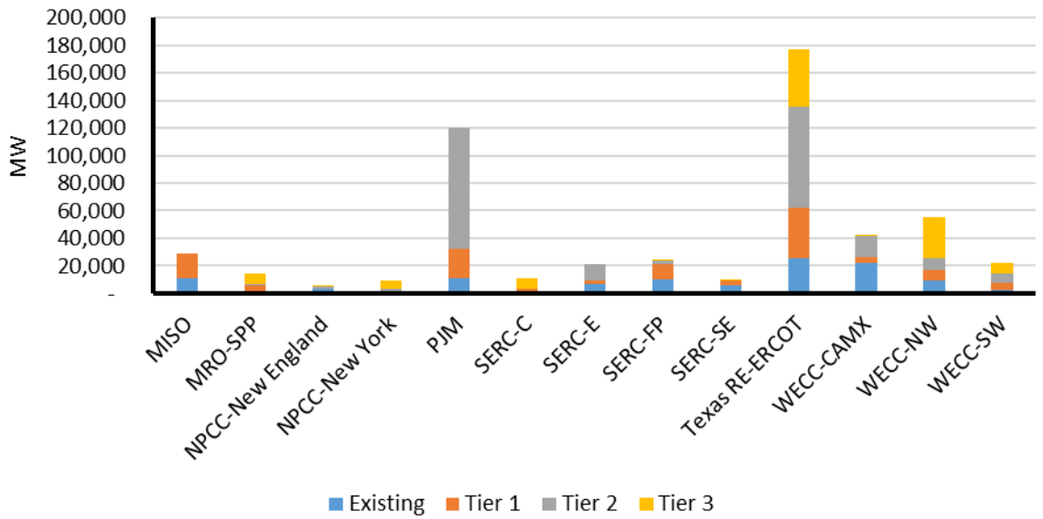


Figure 9: Solar Nameplate Capacity Existing and Planned through 2034

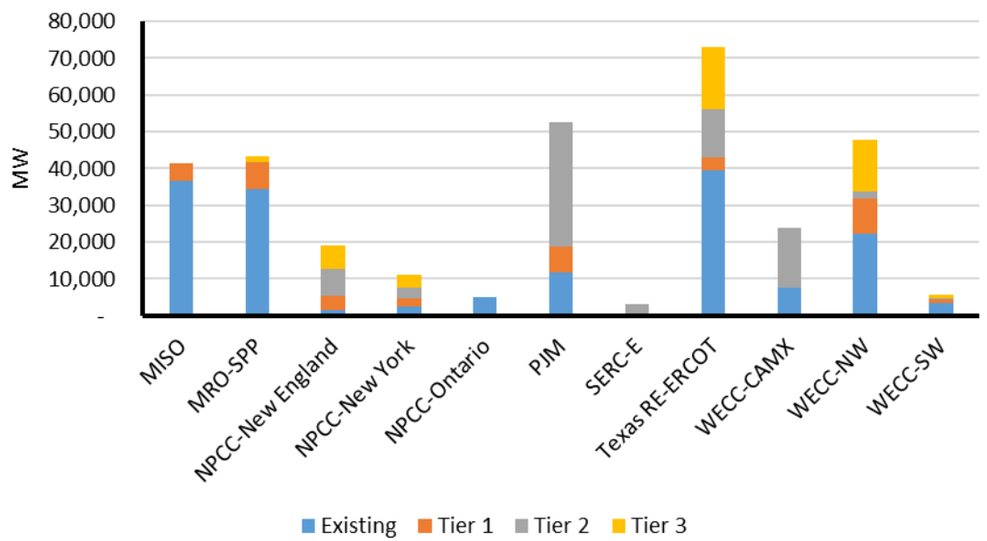
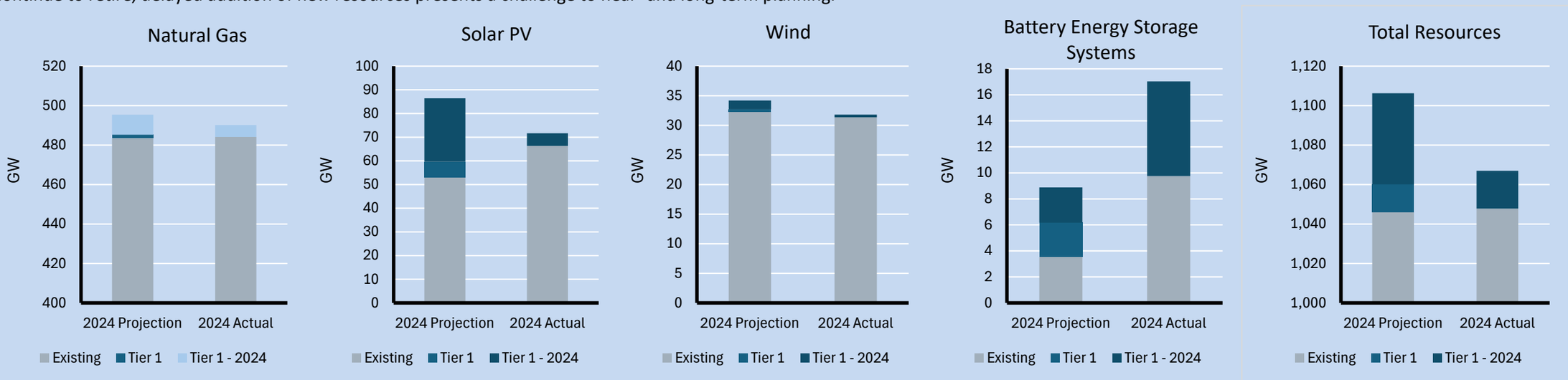


Figure 10: Wind Nameplate Capacity Existing and Planned through 2034

Resource Additions – How Much and When?

The added resource capacity on the BPS over the past year fell short of industry's projections, raising concerns that demand growth has the potential to outpace supply resources. The figures below compare the *2023 LTRA* projection of this year's installed capacity against the actual current installed capacity derived from data collected for this LTRA. Natural gas, solar PV, and wind resources were all over-projected last year. This gives evidence to industry reports of construction delays that prevented the expected interconnection of new resources. To a lesser extent, project withdrawals prior to commercial operation also contributed to lower-than-expected resource additions. One key exception—battery energy storage systems (BESS)—came in higher than last year's projections. As baseload and dispatchable generation continue to retire, delayed addition of new resources presents a challenge to near- and long-term planning.



Comparison of Projected Capacity from the 2023 LTRA to the Actual Capacity in the *2024 LTRA*

The sluggish rate at which new generation moves through the interconnection queue and begins service has been a cause for concern for long-term reliability planning. The Lawrence Berkeley National Laboratory published the results of an interconnection queue study in April 2024 assessing that less than one-fifth of generation capacity projects seeking interconnection between 2000 and 2018 actually came to fruition by the end of 2023.[16] Wait times have also been on the rise: According to the same study, the time from initiating a request for interconnection to the start of commercial operations has increased from less than two years, as was the case from 2000–2007, to more than four years from 2018–2023. The delay in bringing new generation capacity online in assessment areas that are anticipating steady or accelerated thermal capacity retirements, as well as increased demand, presents a significant reliability risk.

In recognition of the interconnection backlog risk, some regional transmission organizations have taken steps to address the lagging completion rates. MISO has assigned multiplication factors to generator requests based on the study phase and the likelihood of that resource coming on-line to more accurately gauge the likely incremental capacity in its footprint.[17] MISO also continues to advance the Joint Targeted Interconnection Queue (JTIQ) with SPP to resolve binding constraints that have delayed the interconnection process. PJM analyzed the completion rate of its interconnection queue and reported that less than 16% of resources submitted into the queue between 1999 and 2023 went into operation. The ISO has also applied a reduction to the nameplate capacity of value of Tier 1 resources to reflect the historical addition rate of new generation. PJM's interconnection process subcommittee is working on enhancements for new generation to interconnect as a capacity resource. These measures and others are examples of the broader effort to streamline generator additions and thus offset retiring capacity.

Offshore wind plants are increasingly entering interconnection queues, located around the Northeastern United States. **Figure 11** shows the current planned capacity in the planning process through 2034 by assessment area. Currently, the existing offshore wind nameplate capacities are small in comparison: a single 29 MW plant in NPCC-New England and a 12 MW plant in PJM.

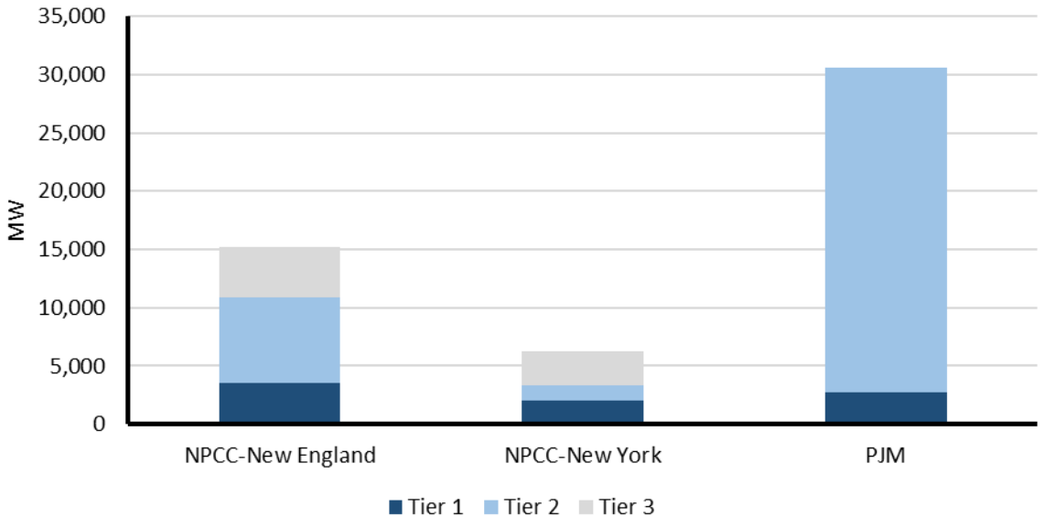


Figure 11: Offshore Wind Capacity Planned through 2034

Battery Resources

As the BPS increases the share of energy provided by VERs, the ability to provide energy by BESS or hybrid-solar PV and wind plants is increasingly important. While currently installed capacity totals just over 17 GW, an additional 306.5 GW of BESS are in planning. **Figure 12** shows the nameplate capacity of BESS resources currently in operation and in planning for connection to the BPS through 2034.

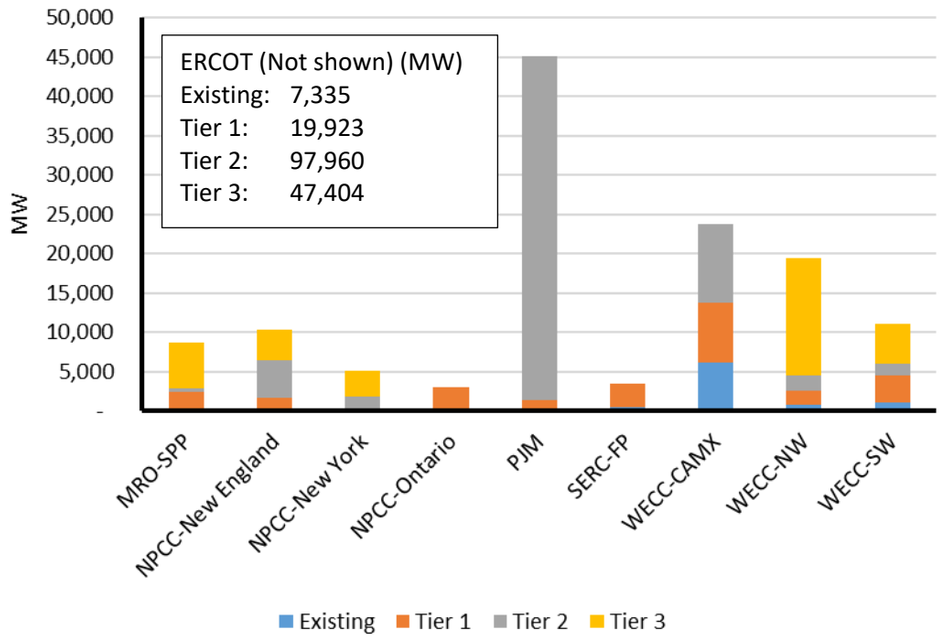


Figure 12: Battery Resource Capacity Existing and Planned through 2034

BESS are improving reliability by helping to offset the variability and uncertainty of inverter-based resources (IBR). BESS are, however, a relatively new type of grid resource with unique operating characteristics. The joint *NERC-WECC Staff Report: 2022 California Battery Energy Storage System Disturbances*[18] highlights an event when a BESS, like some other IBRs, failed to properly ride through a normal system fault. This indicates that BESS must be included in the currently underway strategies to address IBR performance issues.

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. **Table 14** shows the nameplate value and the capacity contribution of existing wind, solar PV, hydro, and energy storage systems resources at the peak demand hour for each assessment area. During risk periods after peak demand (e.g., U.S. assessment areas in WECC), contributions of solar PV resources output is diminished during evening periods and additional resources are needed.

[18] NERC–WECC *2022 California Battery Energy Storage System Disturbances*

Table 14: BPS Wind, Solar, Hydro, and Battery Generation Resources by Assessment Area Year 2024												
Assessment Area	Wind			Solar			Hydro			Energy Storage Systems		
	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)
MISO	41,349	5,715	13.8%	30,502	5,305	17.4%	2,450	1,576	64.3%	401	84	21.0%
MRO-Manitoba Hydro		52	-	-	-	-	6,434	5,704	88.7%	-	-	-
MRO-SaskPower	815	164	20.1%	30	-	-	864	862	99.8%	-	-	-
MRO-SPP	34,475	5,134	14.9%	703	275	39.1%	5,633	4,079	72.4%	2	2	100%
NPCC-Maritimes	-	261	-	-	5.1	-	1,361	1,312	96.4%	-	-	-
NPCC-New England	2,548	127	5.0%	3,361	308	9.2%	1,917	1,469	76.6%	26	9	34.9%
NPCC-New York	2,706	461	17.1%	1,039	240	23.1%	4,915	3,736	76.0%	60	30	50.2%
NPCC-Ontario	4,943	1,364	28%	478	-	0.0%	8,748	6,215	71.0%	18	-	0.0%
NPCC-Québec	3,820	1,375	36.0%	10	-	0.0%	40,907	39,354	96.2%	-	-	-
PJM	11,701	1,760	15.0%	10,735	4,808	44.8%	3,071	2,367	77.1%	222	100	44.8%
SERC-C	982	172	17.5%	2,308	771	33.4%	4,995	3,364	67.4%	100	50	50.0%
SERC-E	-	-	-	6,777	4,753	70.1%	3,170	3,016	95.1%	15	6	38.4%
SERC-FP	-	-	-	10,121	5,618	55.5%	-	-	-	538	523	97.2%
SERC-SE	-	-	-	7,267	5,414	74.5%	3,293	3,260	99.0%	115	40	34.9%
Texas RE-ERCOT	39,532	11,062	28.0%	31,058	19,098	61.5%	583	458	78.6%	10,720	-	0.0%
WECC-AB	5,559	1,867	33.6%	3,042	-	0.0%	894	285	31.9%	270	264	97.8%
WECC-BC	776	279	36.0%	2	-	0.0%	16,902	12,623	74.7%	-	-	-
WECC-CA/MX	7,694	1,158	15.0%	24,905	14,641	58.8%	10,211	3,582	35.1%	11,883	11,155	93.9%
WECC-NW	23,518	3,489	14.8%	12,787	6,877	53.8%	41,257	21,168	51.3%	1,909	1,231	64.5%
WECC-SW	3,784	628	16.6%	5,944	2,527	42.5%	1,025	721	70.3%	2,997	2,592	86.5%

Solar PV Distributed Energy Resource Growth

Behind-the-meter (BTM) solar PV generators are solar PV resources connected on the distribution system, such as residential rooftop solar systems. The rapid growth of BTM solar PV continues with cumulative levels expected to reach over 123 GW by the end of this 10-year assessment period (up from 89 GW reported in the *2023 LTRA*, an increase of 38%). There are currently 58.7 GW of installed BTM solar PV across the North American BPS.

BTM solar PV generators, like grid-connected solar PV, are also VERs. In large penetrations, their predictable change in output from the time of day contributes to steep ramps in demand. As the sun sets and output diminishes, grid resources must make up for the decrease in solar generation and increase in demand that was being served. The opposite ramp occurs during morning hours; it may be less impactful to reliability but can be challenging for grid-connected generator scheduling and dispatch. **Figure 13** shows the current and projected BTM solar PV by area through 2034.

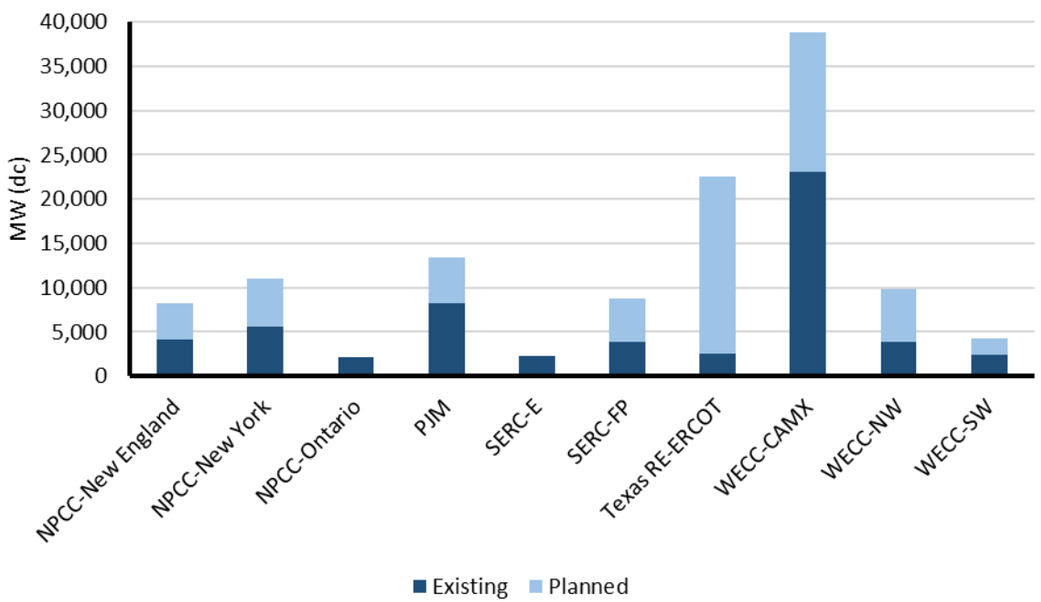


Figure 13: Solar PV DER Capacity Existing and Planned through 2034

Generation Retirements

The total capacity of traditional baseload generation fuel types will continue to decline as older generators retire. Generators become confirmed for retirement according to various processes in place in the Interconnections, such as regional planning tariffs in the wholesale electricity market areas or the integrated resource planning process in vertically integrated states. Properly designed mechanisms can prevent generators from retiring before planners can study and address reliability issues that could occur.

Currently, over 79 GW of fossil-fired and nuclear generating capacity is being retired over this assessment period (see **Figure 14**), a small decrease from the 83 GW in retirements reported in the *2023 LTRA*. This capacity includes generators that are confirmed for retirement through retirement planning processes or that have indicated plans to retire to an ISO/RTO or Planning Coordinator.

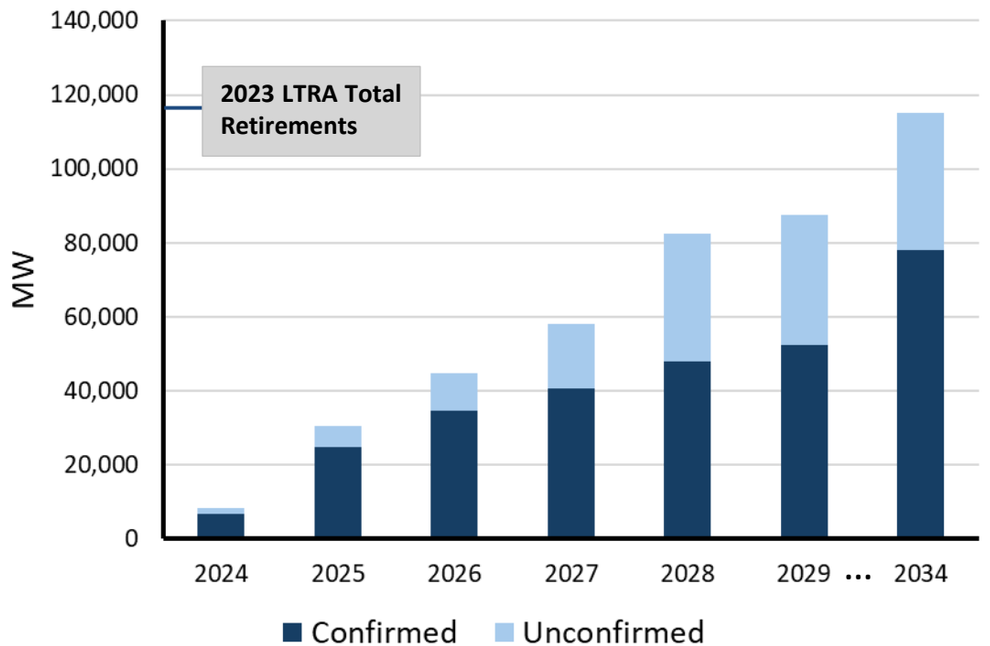


Figure 14: Projected Generation Retirement Capacity through 2034

Additional fossil-fired generator retirements are expected and would result in further loss of existing capacity. Generator Owners often announce plans to retire generator units before initiating the

interconnection planning process, and the announced plans or timing may be subject to change before the retirement is confirmed. Wholesale electricity market areas, where merchant electric generators make up a large part of the generating fleet, have more uncertainty around future generator retirements, making resource planning and adequacy assessment difficult. **Figure 15** shows the total capacity of reported retirements (i.e., reported to ISO/RTOs and planning entities) as well as owner-announced, unconfirmed retirements of fossil-fueled and nuclear generators across the BPS over the next 10 years in each assessment area.[19] This total of confirmed and announced-potential retirements over the next 10 years is over 115 GW (3 GW lower than 10-year projections in the *2023 LTRA*).

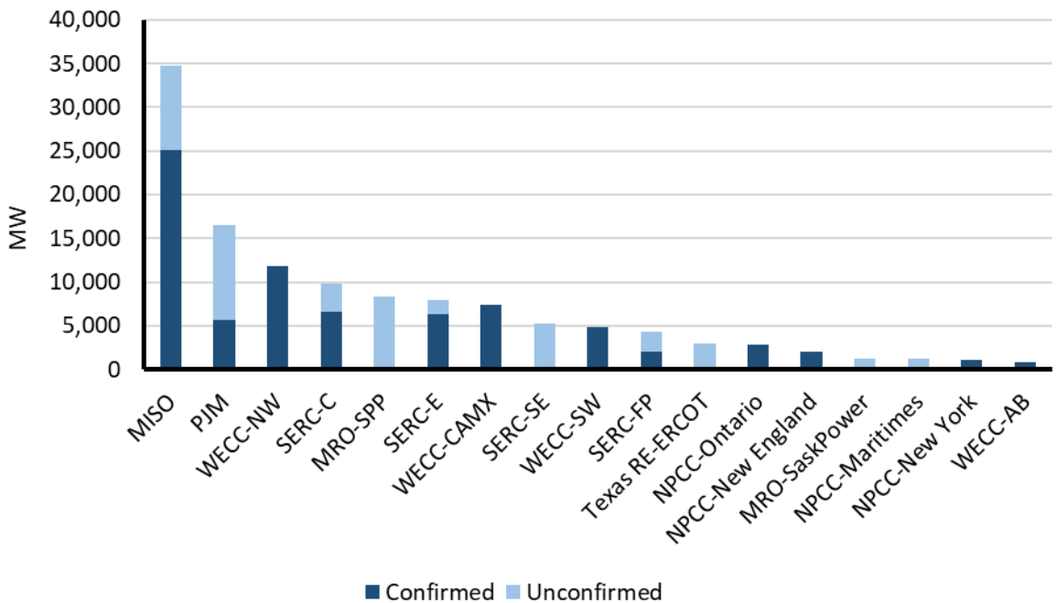


Figure 15: Projected Capacity Retirements of Nuclear and Fossil Generation 2024–2034

Natural Gas Fuel Reliance Trends

Natural-gas-fired generators are and will remain a critical resource for BPS reliability in many areas over the 10-year assessment period, especially during winter. These generators provide many necessary reliability attributes that are exiting the system as traditional generators retire and inverter-based renewable resources take their place in the resource mix. Natural-gas-fired generators are dispatchable and provide the ERSs of inertia, frequency response, and ramping flexibility. In winter, when peak demand in most areas occurs during early morning hours, natural-gas-fired generation is at its highest contribution to the resource mix in many areas. Severe winter weather events in 2021 and 2022 provided stark evidence of the critical nature of natural gas as a generator fuel and the importance of secure supplies during times of extreme electricity demand.

As the generation resource mix evolves and becomes more weather-dependent, fuel assurance becomes increasingly critical when conducting reliability assessments. Until recently, comparing seasonally available capacity to a predetermined PRM level has sufficed as a means to assess resource adequacy. However, resource adequacy is now only the first step of a meaningful reliability assessment. Energy adequacy must now be layered on top to assess the risk that available capacity may be rendered unavailable due to phenomena including low wind or solar output and/or natural gas supply and transportation issues.

This year, the Energy Information Administration (EIA) projected that more than 40% of delivered natural gas would be consumed by power generators, more than 0.6 Bcf/d higher than was consumed by power generators in 2023 and 7% higher than what the EIA had projected for 2024 in the fall of last year. Natural-gas-fired power plants generated 42% of the electrical energy consumed by end-use electricity customers in 2023 and are on track to maintain that share of generation this year. A significant percentage of natural-gas-fired power plants rely upon as-available, non-firm gas supply and transportation arrangements. Non-firm natural gas supply and transportation is generally sufficient for electric generators most of the year. However, during extreme cold weather, demand for natural gas by both generators and natural gas distribution companies (generally firm shippers) can at the same time dramatically increase. In these instances, generators that lack firm supply and transport arrangements are at risk of fuel unavailability, and when winter weather impacts gas production facilities, the resulting imbalance in pipeline injections and withdrawals can put at risk even firm pipeline customers as preparatory linepack is rapidly depleted.

[19] Confirmed generator retirements are reported to NERC by each assessment area in this *2024 LTRA* development process. NERC obtained data on announced, unconfirmed generator retirements from Energy Ventures Analysis, Inc. and from each assessment area. Some sources of information on announced generator retirements include EIA 860 data, trade press, and utility integrated resource plans.

The *2024 LTRA* projects that an additional 6,500 MW of new natural-gas-fired generation will be added in North America over the next five years. While some assessment areas project net decreases in natural-gas-fired capacity, other areas report increases ranging from 3% to over 50%.

In the United States, 8 out of 13 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years, amounting to over 10 GW of new natural-gas-fired power capacity. Altogether, those additions translate to an increase in natural gas use for power generation of more than 84 Bcf (245 MMcf/d). Whether this increase in natural gas generation capacity is sufficient to meet the increase in net internal demand projected for these same assessment areas remains to be seen, but based on the capacity additions alone, some areas are set to see an insufficient increase in gas pipeline capacity, as per the EIA's database of nationwide U.S. gas pipeline projects. (see **Figure 16**).

PJM is one such area, projected to see a 3% increase in natural-gas-fired generation capacity (+2,500 MW). Net internal electricity demand in PJM is forecasted to rise by 25 GW over the planning horizon at the same time that non-variable resources are expected to shrink their share of the capacity mix from 96% to 88%. To the extent that variable resources are uncertain during times of peak stress on the grid, there is a risk of gas delivery capacity being insufficient for the amount of natural gas supply that could be required to meet the demand increase. SPP is another assessment area where natural-gas-fired power capacity is set to rise, by 5%, or roughly 1,500 MW. In both PJM and SPP, there is a risk of a shortfall in natural gas pipeline capacity that could facilitate delivery of the additional fuel that is necessary to meet their capacity expansion plans.

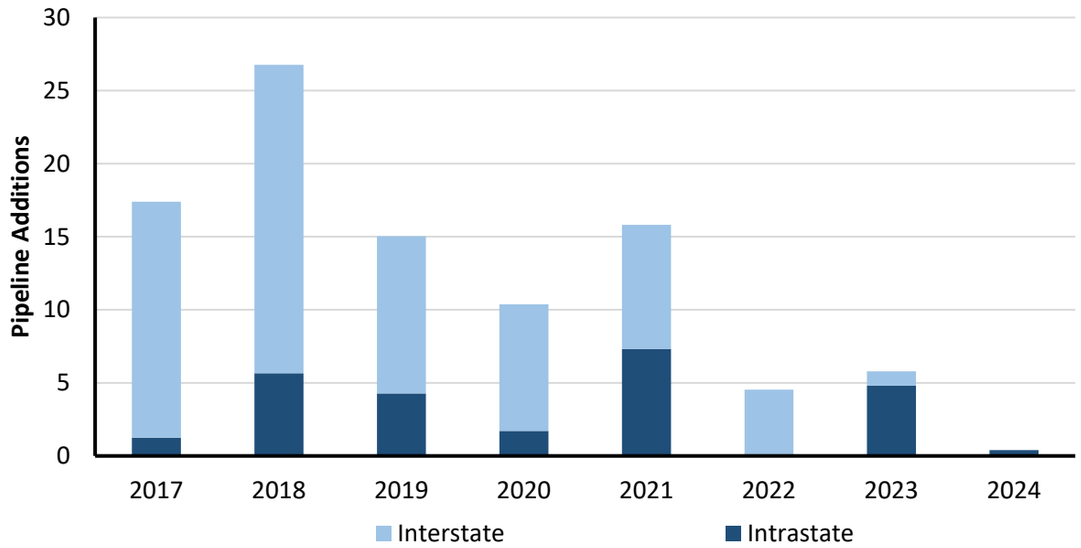


Figure 16: Annual U.S. Natural Gas Pipeline Capacity Additions by Type (2017–2024) Bcf/d (Source: U.S. Energy Information Administration)

Reliability Implications

The addition of variable resources, primarily wind and solar PV, and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. With electricity supplies coming increasingly from VERs and natural-gas-fired generators, there is a growing risk that supplies can fall short of demand during some periods. Geographically diverse wind and solar resources and loads can help reduce these risks, but they require robust transmission networks, comprehensive energy and transfer capability analysis, and effective operating procedures and market mechanisms.

Maintaining ERSs for Grid Support

For the grid to operate reliably, it needs resources that are not only sufficient for meeting demand and energy requirements but also capable of controlling voltages, maintaining stable frequency across the system, and flexibly ramping up or down to dispatch control at all times. Conventional generators, such as nuclear, coal, and natural gas-fired generators, provide much of the ERSs that support reliable operation today. New resources on the grid are almost all IBRs, which have different physical and operating characteristics that affect the level of ERSs that they can provide. Without the spinning mass or traditional excitation systems providing the voltage control of a hydroelectric or thermal generator,

most IBRs have limited capability for maintaining system voltages and stability. Batteries, with their fast response time, have some ERS capability that wind and solar do not. They are useful in regulating system frequency and are helping to balance variability from VERs in ERCOT and California where wind and solar make up a large portion of the resource mix.[20] As generators are deactivated and replaced by new types of resources, ERSs must still be maintained for the grid to operate reliably.

Accelerated generator retirements, especially unanticipated requests for deactivation, can cause ERS-related reliability issues in parts of the system due to the future loss of the generator's reliability attributes. This reduction in the level of ERSs can result in voltage violations or system instability. System planning and generator deactivation processes evaluate these changes to the system and ensure plans proceed only when reliability criteria, including ERS-related considerations, are met. For example, PJM's deactivation process identified reliability concerns to the system as a result of the requested deactivation of the Brandon Shores power plant (1,280 MW) in 2023. Until necessary system upgrades are completed to address identified system voltage and other reliability issues that would occur with the deactivation, PJM has requested that the Brandon Shores generators at the plant remain in service through the reliability-must-run process.[21]

To ensure the future system can operate reliably, market operators, system planners, regulators, and policymakers need to ensure effective mechanisms are in place to provide for the ERS needs of the future system. Long-term activities can provide incentives to generators with needed reliability attributes. Effective backstops will also be needed to prevent the loss of critical generators when analysis finds deactivation would violate reliability criteria.

Specific and actionable recommendations are contained in the **Recommendations and ERO Actions Summary** section of this report.

[20] See the *2023 Special Report on Battery Storage* from the California ISO.
[21] Information on this and other proposed deactivations in PJM are found on PJM's Generator Deactivations page.

Demand Trends and Implications

Demand and Energy Projections

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. The aggregated assessment area summer peak demand forecast is expected to rise by over 132 GW, and aggregated winter peak demand forecasts are increasing by 149 GW. The growth rates of forecasted peak demand (see **Figure 17**) and energy (see **Figure 18**) continue to rise sharply since the 2022 LTRA, reversing an almost two-decade trend of falling or flat growth rates. See **Figure 17** for seasonal peak demand growth over the current and prior assessment periods and **Figure 18** for net energy growth. A map of the primary demand drivers for the North American BPS is illustrated for each assessment area in **Figure 19**.

Electrification and Demand Growth

Electrification of household appliances (e.g., heat pumps for household heating) and projections for electric vehicle growth over this assessment period are components of the demand and energy estimates provided by each assessment area. Since the *2023 LTRA*, peak season CAGR has risen in all assessment areas except two: NPCC-Maritimes' winter CAGR fell from 0.98% to 0.63% and WECC-BC's winter CAGR fell from 1.05% to 0.28%. Rising peak demand forecasts are contributing to the lower reserve margins projected for nearly all assessment areas.

Large Commercial and Industrial Loads

Increasing amounts of large commercial and industrial loads are connecting rapidly to the BPS. Emerging large loads, such as data centers (including crypto and AI) and hydrogen fuel plants, present unique challenges to forecasting and planning for increased demand. Earlier this year, NERC's RSTC established a Large Loads Task Force to better understand the reliability implications of growth in large loads and develop solutions.

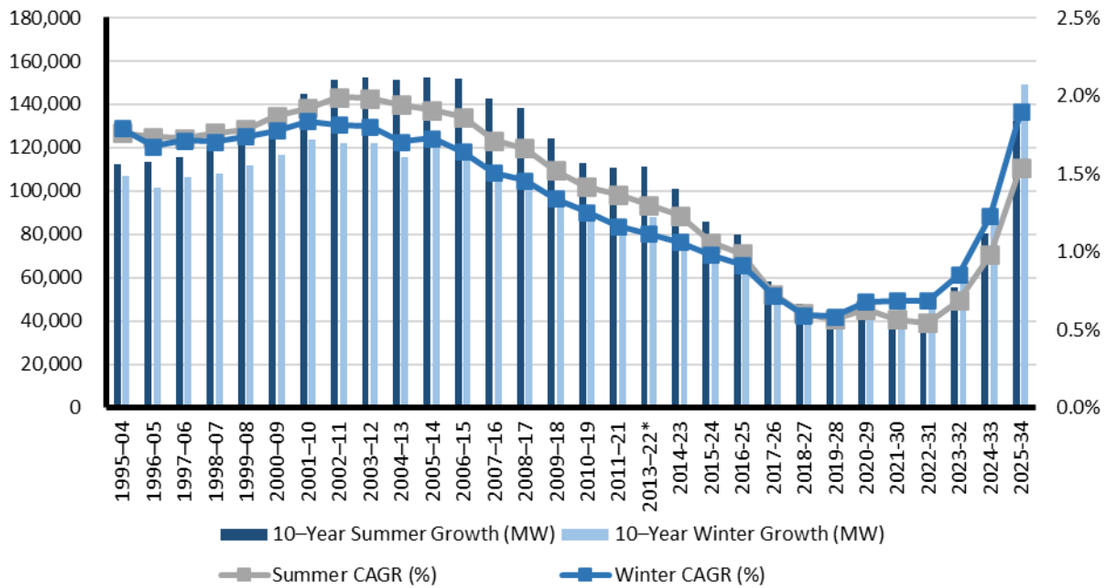


Figure 17: 10-Year Summer and Winter Peak Demand Growth and Rate Trends



Figure 18: Net Energy for Load Growth and Rate Projections

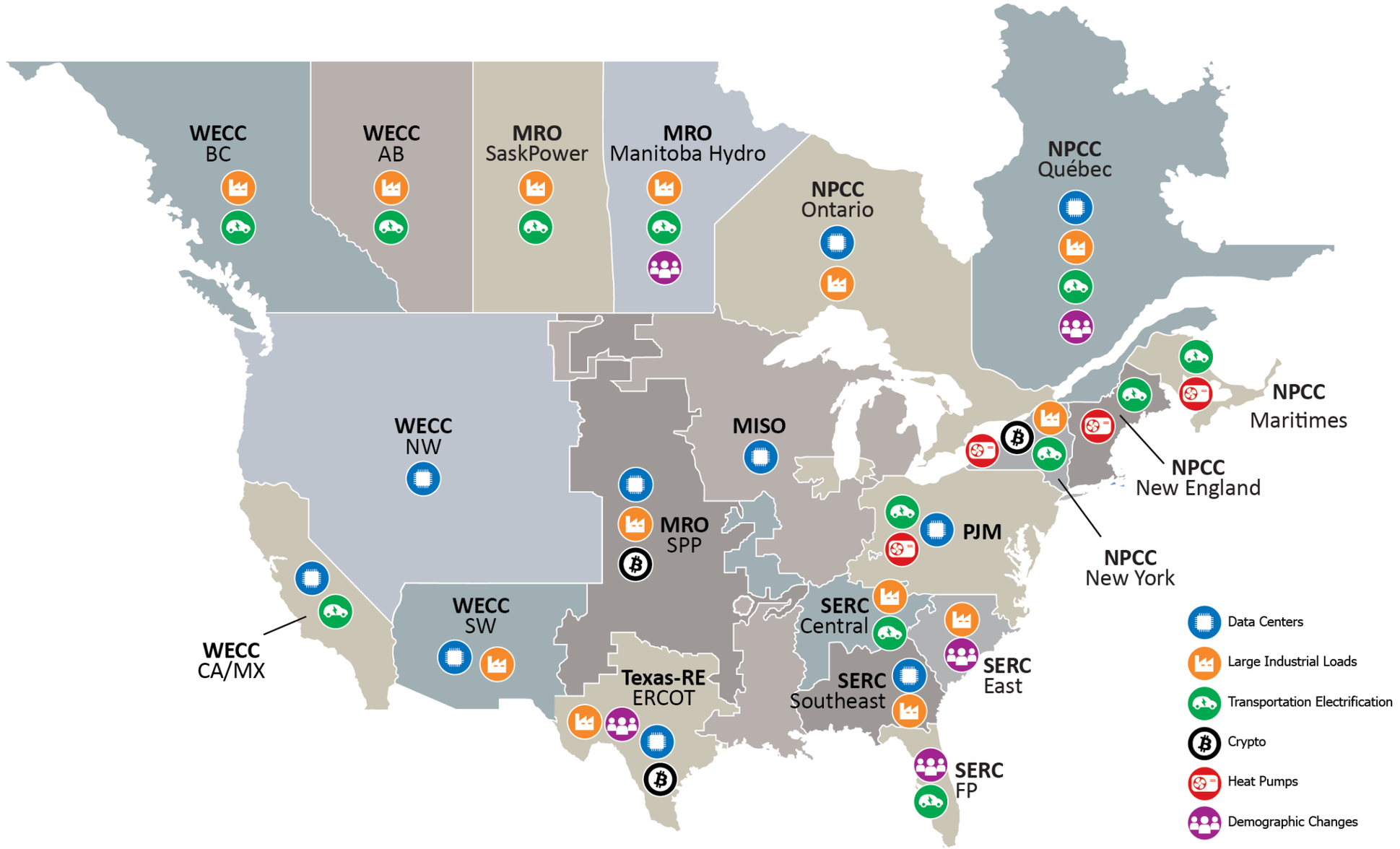


Figure 19: Primary Demand Drivers by Assessment Area

Peak Season Transition

Some of the sharpest peak demand forecast increases and growth rates can be seen in winter seasons as electrification in heating systems and transportation influence forecasts. Dual-peaking or changing from summer to winter peaking is anticipated in several areas, including the U.S. Southeast and Northeast. Electrification of heating systems and the anticipated growth of electric vehicles (which are expected to charge overnight and coincide with periods of electricity demand for heating) are driving factors. Such changes have wide-ranging implications for how the grid and resources are planned and operated. For example, resource output and fuel risks are significantly different in winter, requiring the focus of resource adequacy processes to change. The following are the areas that anticipate a change from a summer-peaking system to a winter-peaking (or dual-season peaking) system and the approximate year of the transition:

- NPCC-New England (mid-2030s)
- NPCC-New York (mid to late-2030s)
- NPCC-Ontario (2030)

In the U.S. Southeast, SERC-Central and SERC-East became dual-peaking systems in recent years. SERC-Southeast recently began experiencing slightly higher peak demand in winter compared to summer.

Reliability Implications

Demand and energy growth projections in this assessment period provide both challenges and opportunities for electric grid reliability. Planning for resource and transmission adequacy requires accurate long-term forecasting, but future demand and energy use will be influenced by many factors, including the economy, energy policies, technology development, weather, and consumer preferences. Changing patterns in electricity use, load behavior, and distributed energy resource performance affect the accuracy of operational load forecasts that are essential to grid operators. Large flexible loads and demand-side management programs hold promise for peak load management capabilities that can reduce the risk of firm load interruption.

Anticipating large commercial and industrial loads, electrification, electric vehicle adoption, and the impacts of energy transition programs on future demand and energy needs will require even more focus for planners and operators. Peak demand forecast changes in the past year had a noticeable effect on resource adequacy for many areas. A confluence of factors (economic, energy policies, technology development, and consumer preferences) has the potential to fuel continued growth.

Transmission Development and Interregional Transfer Capability

Transmission Projects

This year's cumulative level of 28,275 miles of transmission (>100 kV) in construction or stages of development for the next 10 years (see **Figure 20**) is substantially higher than the *2023 LTRA* 10-year projections (18,675 miles) and is above the average of the past five years of NERC's LTRA reporting on average (18,900 miles of transmission planning projects in each 10-year period published in the last five LTRAs). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning phases.

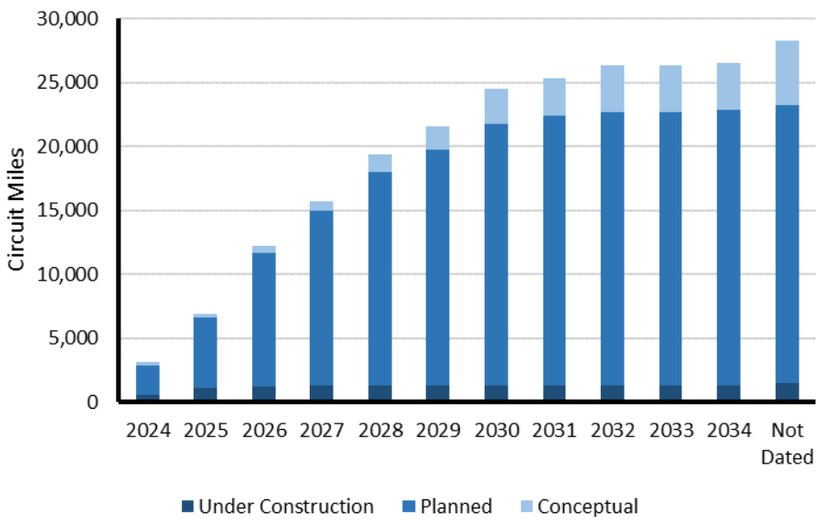


Figure 20: Future Transmission Circuit Miles >100 kV by Project Status

New transmission projects are being driven to support new generation and enhance reliability. **Figure 21** shows the percentage of future transmission circuit miles by primary driver. Most projects reported this year have been initiated for the purpose of grid reliability, which generally includes transmission projects that are needed to ensure that the BPS operates within established limits and design criteria. Some substantial new projects to integrate renewable generation are also in development or are entering planning processes. Nearly 70 of the 1,160 transmission projects in development are for tie-lines and tie-line upgrades, which support transfer capability between neighboring Balancing Authority areas. See the transmission summaries at the end of each assessment area's pages (in the **Regional Assessments Dashboards**) for current transmission development details.

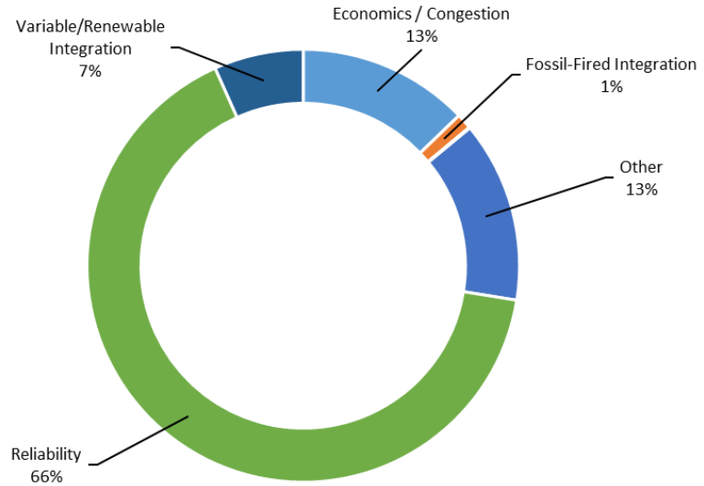


Figure 21: Future Transmission Circuit Miles by Primary Driver

Transmission development in some areas is hampered by siting and permitting challenges. Of the 1,160 projects that are under construction or in planning for the next 10 years, over 110 projects are currently delayed from their expected in-service dates. Siting and permitting issues are the most common cause for delays, affecting 68 projects (totaling 1,230 miles of new transmission). Other reasons for delays include economic impacts, planning and construction issues, or changing needs.

Interregional Transfer Capability Study (ITCS)

The Fiscal Responsibility Act of 2023[22] required NERC to conduct a comprehensive study of existing and future interregional transfer capability between each Transmission Planning Region[23] (TPR) to make recommendations for prudent additions to the amount of power that can be moved or transferred between neighboring TPRs and to make recommendations on how to meet and maintain transfer capability. In addressing this legislation, NERC identified additions to transfer capability that could support energy adequacy.[24] NERC filed the completed study report with FERC on November 19, 2024.[25]

Transfer Capability is the measure of the ability of the interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all the transmission lines (or paths) between those areas under specific system conditions. The units of transfer capability are in terms of electric power, generally expressed in MW.

To provide further opportunities for stakeholder engagement and consultation, the project was divided into several stages, each with an accompanying report.

- **Overview of Study Need and Approach[26]:** Provided background and context regarding transfer capability calculations and the approach for recommending prudent additions, laying the foundation for the ITCS as a whole and its associated methods. (published in June 2024)
- **Transfer Capability Analysis (Part 1)[27]:** Addressed the first part of the congressional directive, which mandated a transfer capability analysis between each pair of neighboring TPRs, as well as the simultaneous import capability of each TPR. (published in August 2024)
- **Prudent Additions Recommendations (Part 2) and Meet/Maintain Recommendations (Part 3)**: Contained an energy margin analysis and resulting recommendations for prudent[28] additions to the transfer capability between neighboring TPRs to improve energy adequacy during, for example, extreme weather events. It also discussed how to meet and maintain transfer capability as enhanced by these prudent additions.
- **Canadian Analysis:** Due to the interconnected nature of the BPS, NERC will extend the study beyond the congressional mandate to identify and make recommendations to transfer capabilities from the United States to Canada and among Canadian provinces.[29]

Transfer Capability Analysis (Part 1)

Adequate transfer capability is fundamental to the reliable operation of the BPS. Balancing Authorities may rely on their neighbors to supply energy for various purposes, including economic or policy reasons. Transfer capability is also essential under stressed operating conditions, allowing Balancing Authorities to maintain reliability by importing needed energy from their neighbors. As the resource mix becomes increasingly dependent on just-in-time and weather-dependent fuel and energy for wind and solar, the ability to transfer electrical energy from areas of surplus to areas experiencing fuel or energy constraints has become essential to maintaining reliable delivery of electricity to end-use customers.

The ITCS is a congressionally mandated study to evaluate transfer capability and recommend additions to strengthen reliability.

A holistic view of the interconnected system and a thorough understanding of its behavior are essential when calculating or increasing transfer capability. When neighboring TPRs transfer energy over a highly interconnected system, the energy flows over many different lines based on the electrical characteristics, or impedance, of traveling each route, unless there is specific equipment used to control flows. As a result, energy typically flows not only across the tie lines that directly connect the exporting (source) TPR to the importing (sink) TPR but over many routes, some of which

[22] H.R.3746 - 118th Congress (2023–2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress
[23] For the purposes of the ITCS, this term refers to the study regions as described in ITCS Overview of Study Need and Approach, Chapter 2.
[24] As evidenced during recent operational events including Western Interconnection Heatwave (2020), Winter Storm Uri (2021) and Winter Storm Elliott (2022), more needs to be done to support energy adequacy to be able to continuously meet customer demand. This is the reliability risk that the ITCS seeks to identify and mitigate through additions to transfer capability.
[25] NERC filing of the Interregional Transfer Capability Study, FERC Docket AD25-4-000.
[26] The ITCS Overview of Study Need and Approach can be found here.
[27] The ITCS Transfer Capability Analysis (Part 1) report can be found here.
[28] FERC defines prudence as the determination of whether a reasonable entity would have made the same decision in good faith under the same circumstances at the relevant point in time. See, e.g., New England Power Co., 31 FERC ¶61,047 at p. 61,084 (1985); and PotomacAppalachian Transmission Highline, LLC, 140 FERC ¶61,229 at P 82 2012 (Sept. 20, 2012).
[29] The ITCS Part 1 evaluated transfer capability from Canada into the United States.

may be running through third-party systems. The way electrical energy flows has broad implications for calculating and using transfer capability in an interconnected system, especially when traveling over long distances. For example, maintaining and increasing transfer capability may be highly dependent on the system conditions within the source and sink TPRs as well as surrounding areas. Likewise, transfer capability does not correlate one-to-one with the rating of new or upgraded transmission facilities.

Part 1 Key Findings

- Transfer capability varies seasonally and under different system conditions that limit transmission loading—it cannot be represented by a single number.
- Transfer capability varies widely across North America, with total import capability varying between 1% and 92% of peak load.
- Observed transfer capabilities are generally higher in the West Coast, Great Lakes, and Mid-Atlantic areas but relatively lower in the Mountain States, Great Plains, Southeast, and Northeast. There is limited transfer capability between interconnections

The transfer capability results in the Part 1 report reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. This study used a set of cases representative of stressed system conditions most relevant for the Part 2 analysis. As such, the study did not attempt to maximize transfer capability values for each interface through optimal generation re-dispatch, system topology changes, or other operational measures. Consequently, higher transfer capabilities may be available under different conditions. Changes to future resource additions, resource retirements, load forecast changes, and/or transmission expansion plans have the potential to significantly alter the study results.

Recommendations for Prudent Additions (Part 2) and to Achieve Transfer Capability (Part 3)

Part 2 of the ITCS evaluated the energy adequacy of the BPS should past weather conditions occur again in 2033. Specifically, the study applied 12 past weather years to the 2033 loads and resource mix using the current transfer capabilities as calculated in Part 1. The Part 2 study then evaluated the impact that additional transfer capability could have in mitigating the identified resource deficiencies[30] during extreme events, thereby improving energy adequacy. Using a six-step process, the ITCS developed a list of recommended additions to transfer capability. **Figure 22** shows the existing and potential new interfaces where additional transfer capability is recommended. While there are several factors that Transmission Planners consider, including reliability, economics, and policy objectives, given NERC's role as the ERO, the ITCS focused solely on reliability, specifically in terms of energy adequacy, for these recommendations.

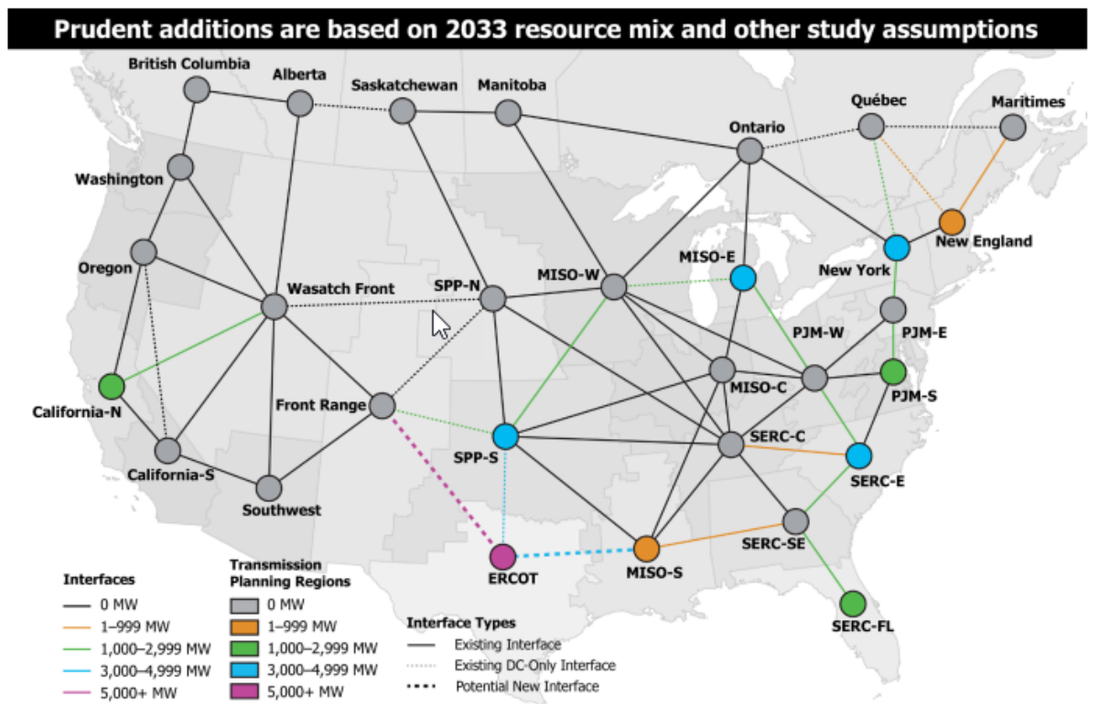


Figure 22: Prudent Additions to Transfer Capability

[30] For the purposes of this study, "resource deficiency" is used to describe instances where available resources, including energy transfers from neighbors, are insufficient to meet the projected demand plus minimum margin level.

The resulting recommendations for prudent additions to transfer capability (Part 2 study) were published in a report along with recommendations to meet and maintain transfer capability as enhanced by the prudent additions (Part 3).[31] Planners have multiple options for reducing the energy adequacy and extreme weather risks. In addition to the transmission enhancements that were in scope for the ITCS, due consideration should also be given to constructing local generation and storage, demand-side management approaches, and grid resilience projects. The ITCS recommended that planners consider all options and balance reliance on external resources vs. internal resources, noting that there may be better options than an over-reliance on one or the other.

Part 2 Key Findings

- Import capability required to reliably serve customers during extreme conditions varied significantly across the country, so a one-size-fits-all requirement would be inefficient and ineffective.
- Transmission limitations and the potential for energy inadequacy were identified in all 12 years studied.
- 35 GW of additional transfer capability is recommended across the United States to improve energy adequacy under extreme conditions.
- Some identified transmission needs could be alleviated by projects already in the planning, permitting, or construction phases. If completed, these projects could mitigate several risks highlighted by the ITCS, reinforcing their importance for grid resilience.
- The ITCS provides foundational insights for further discussion, and decisions. Transmission upgrades alone will not fully address all risks, and a broader set of solutions should be considered, emphasizing the need for local resources, energy efficiency, demand-side, and storage solutions.

See the *ITCS Final Report* for Detailed Key Findings

[31] The ITCS report *Recommendations for Prudent Additions to Transfer Capability (Part 2) and Recommendations to Meet and Maintain Transfer Capability (Part 3)* can be found here.

Emerging Issues

While developing this LTRA, NERC and the industry considered trends and developments that have the potential to impact the future reliability of the BPS over the next 10 years and beyond. Discussed below are emerging issues and trends not previously covered in this report that have the potential to impact future long-term projections or resource availability and operations.

Data Centers and Large Industrial Load

Growth in large load parcels like data centers and industrial facilities pose various challenges for system planners and operators, in addition to fueling rapid demand growth discussed elsewhere in this report. **Figure 23** shows one estimate of data center growth in the United States by 2027.[32] Other types of large industrial loads include smelters, manufacturing centers, hydrogen electrolyzers, and future electrified mass transit or shipping charging stations. Adding large parcels of load on the system can add new uncertainties to peak and hourly load forecasting. For example, data centers have longer operating hours and require more heating and cooling than other commercial buildings. In Texas, crypto mining facilities have connected in recent years that scale their operations (and thus electricity demand) depending on electricity prices. The behavior of large data centers during normal grid faults is also an emerging concern because customer-initiated automatic disconnecting of sizeable load can cause operating issues. Sudden and unexpected disconnecting load during a grid fault is analogous to well-known IBR performance issues and poses similar reliability risks. Planners and operators need to consider the characteristics of these loads as they begin to proliferate and support NERC RSTC's Large Loads Task Force to share best practices.

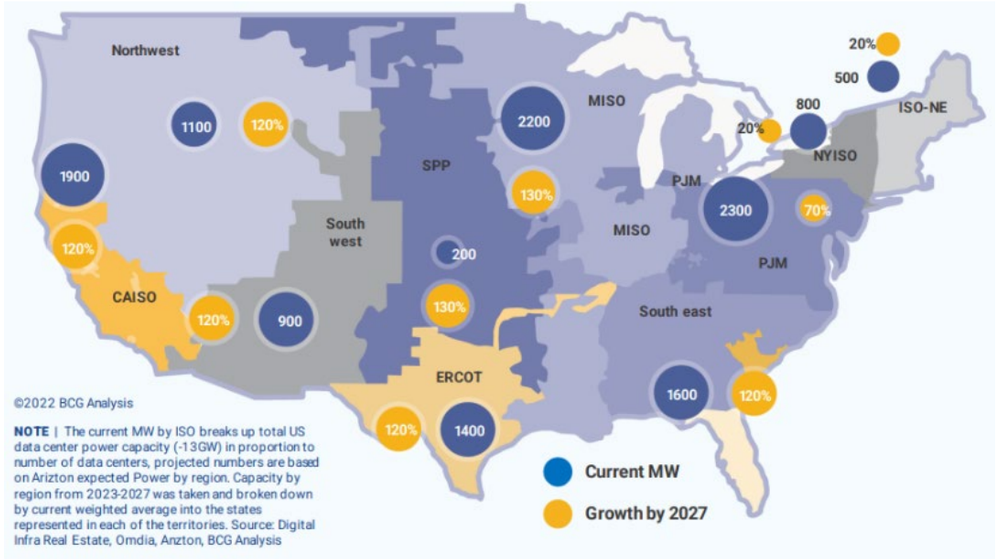


Figure 23: Projected Growth in Data Centers in the United States

Battery Energy Storage Systems

Planners and operators are focused on requirements to model, study, and operate the BPS with increased BESS and hybrid resources. BESS are increasingly being relied upon in areas with substantial amounts of solar PV resources to reduce ramping requirements on other resources by discharging in late afternoon as solar PV output rapidly declines. BESS are also often used for ancillary services, such as frequency response. Accurately accounting for BESS in operating and planning studies is a challenge because it requires assumptions and modeling capabilities for battery charging and discharging behavior. In real-time operations, system operators often do not have visibility into battery state-of-charge, a necessary condition for reliably integrating batteries into system operating plans. Without such information, operators may be surprised should battery resources fail to deliver when needed. In Texas, where battery resource growth is among the highest in North America, ERCOT uses a battery storage data collection program to obtain operational information and is pursuing market rules for state-of-charge accounting in unit commitment processes. System planners in many areas will be counting on new BESS facilities to manage variability and demand and resources. Obtaining the benefits of these resources requires careful integration into operating, planning, and market designs.

[32] *Grid Strategies: The Era of Flat Power Demand is Over*: https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf

Electric Vehicles and Electric Load

With increased adoption of electric vehicles (EV), which use batteries to store energy, there is a need to understand the impact of battery charging on system performance. EV forecasting is important for resource adequacy and system planning to account for changing load and load patterns. It is also important for system studies to include EV modeling and parameterization that account for the behavior of battery charging systems on system performance. In January 2024, NERC released the *EV Charging Study*, noting that the behavior of large amounts of EV chargers in operation can affect the BPS response to common outages. The RSTC established an EV Task Force to promote collaboration among the electric power industry and automotive representatives on areas of grid reliability.

Energy Drought

More reliance on wind, solar, and hydro resources in the resource mix has the potential to expose the electric system to supply shortages under abnormal weather patterns. When two or more resource types are simultaneously affected by conditions that cause below-normal resource output, operators can face challenges in meeting demand. Analysis of U.S. historical hourly generator data indicates that there are regional patterns to energy drought that can be expressed in terms of duration, magnitude, and seasonality (See **Figure 24**). There is also a higher likelihood for energy droughts to be more likely occur during high-load periods than at other times, underscoring the importance in considering such events in planning for resource and storage needs.[33]

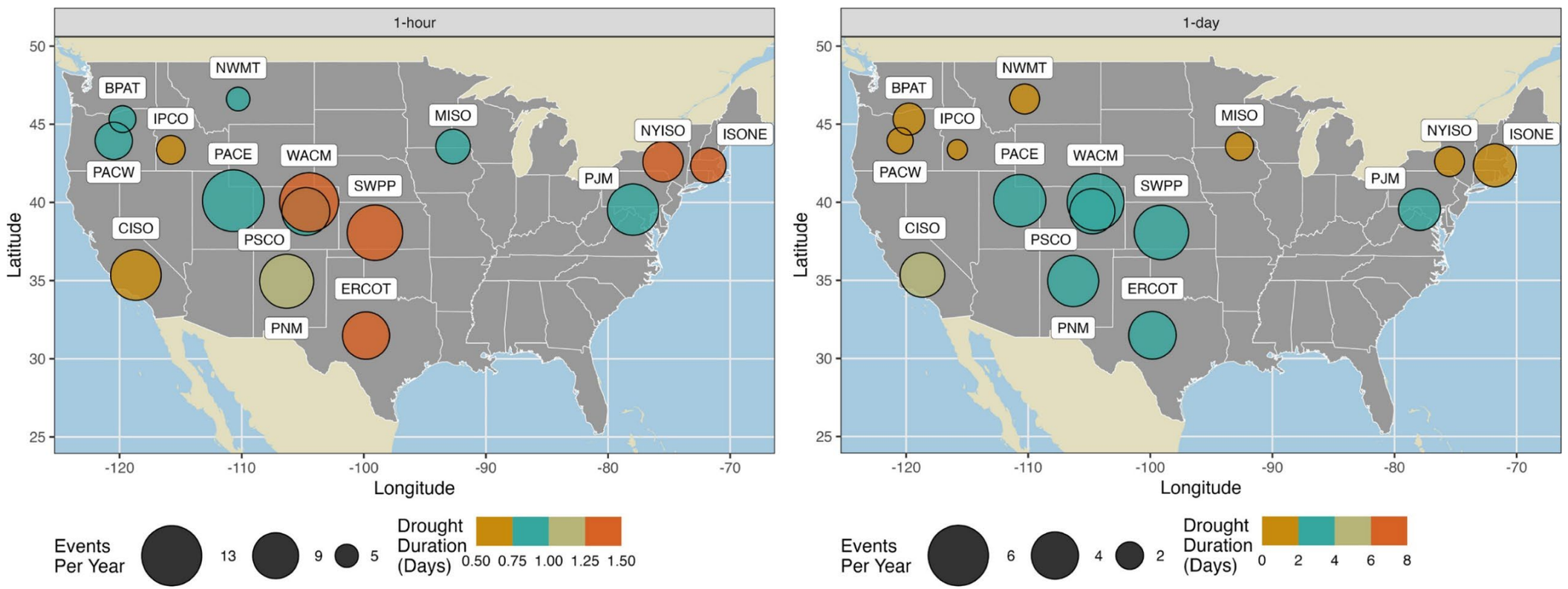
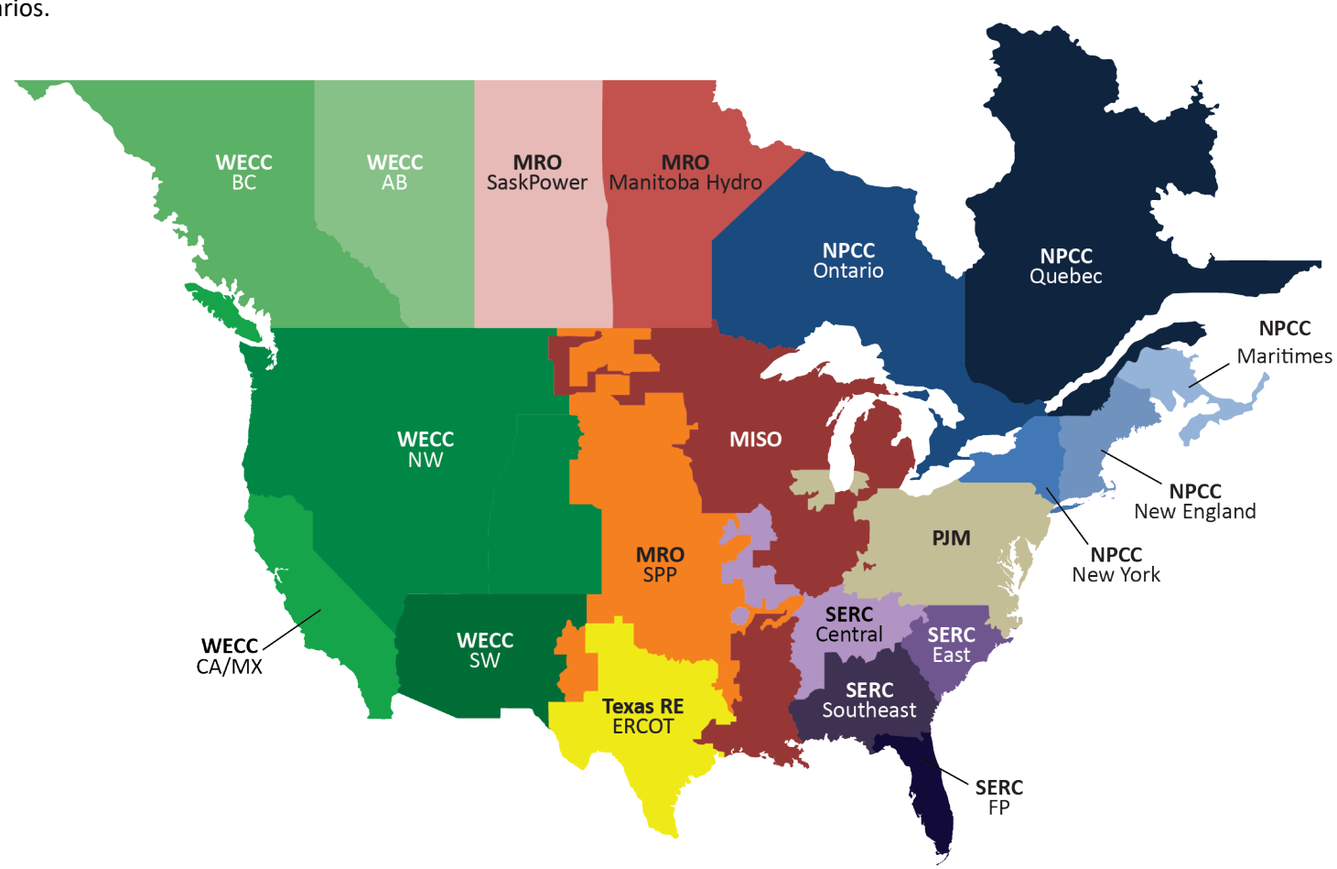


Figure 24: Frequency and Duration of Hourly (Left Panel) and Daily (Right Panel) Energy Droughts. Source: Pacific Northwest National Laboratory

[33] See Standardized benchmark of historical compound wind and solar energy droughts across the Continental United States

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Demand Assumptions and Resource Categories** table. On-Peak Reserve Margin bar charts show the ARM compared to the RML established for the area to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the Demand and Resource Tables), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the Demand and Resource Tables) and the extreme winter peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the WRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios.



- MISO *(Midcontinent Independent System Operator)*
- PJM

MRO – Midwest Reliability Organization
- MRO-Manitoba Hydro
- MRO-SaskPower
- MRO-SPP

NPCC – Northeast Power Coordinating Council
- NPCC-Maritimes
- NPCC-New England
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

SERC – SERC Reliability Corporation
- SERC-Central
- SERC-East
- SERC-Southeast
- SERC-Florida Peninsula

Texas RE – Texas Reliability Entity
- Texas RE-ERCOT *(Electric Reliability Council of Texas)*

WECC
- WECC-AB *(Alberta)*
- WECC-BC *(British Colombia)*
- WECC-CA/MX *(California/Mexico)*
- WECC-NW *(Northwest)*
- WECC-SW *(Southwest)*



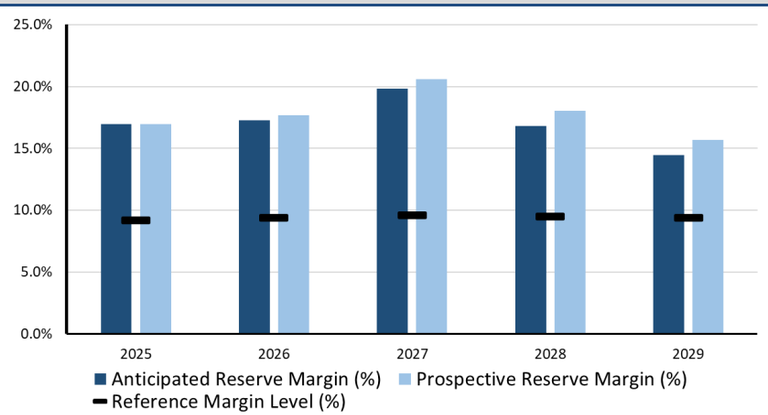
MISO

Midcontinent Independent System Operator, Inc. (MISO) is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authority and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

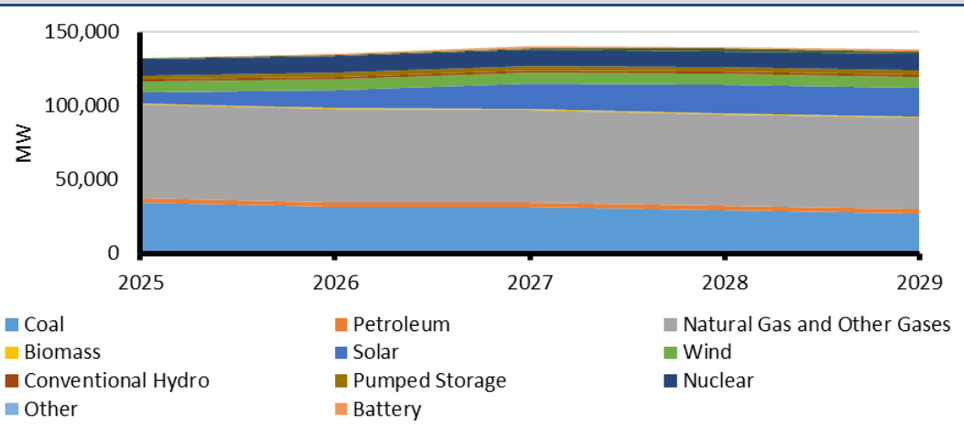
Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	122,328	124,343	126,073	128,700	129,401	130,120	130,493	131,327	131,952	131,952
Demand Response	8,205	8,221	8,058	8,065	8,074	8,077	8,079	8,075	8,075	8,075
Net Internal Demand	114,122	116,122	118,015	120,635	121,327	122,043	122,414	123,252	123,877	123,877
Additions: Tier 1	4,959	11,376	18,275	21,501	22,205	22,205	22,205	22,205	22,205	22,205
Additions: Tier 2	19	464	916	1,486	1,486	1,486	1,486	1,486	1,486	1,486
Additions: Tier 3	803	3,686	8,252	13,017	15,546	16,399	16,542	16,608	16,659	16,659
Net Firm Capacity Transfers	1,320	1,270	1,165	925	855	750	549	549	549	549
Existing-Certain and Net Firm Transfers	128,520	124,787	123,153	119,397	116,669	112,823	110,273	110,273	106,838	106,838
Anticipated Reserve Margin (%)	17.0%	17.3%	19.8%	16.8%	14.5%	10.6%	8.2%	7.5%	4.2%	4.2%
Prospective Reserve Margin (%)	17.0%	17.7%	20.6%	18.0%	15.7%	11.9%	9.4%	8.7%	5.4%	5.4%
Reference Margin Level (%) (Summer)	9.2%	9.4%	9.6%	9.5%	9.4%	9.4%	9.5%	9.6%	9.7%	9.7%

Note: See **Figure 3** for summer reserve margins with historically average resource additions in MISO based on results from the 2024 Organization of MISO States (OMS)-MISO Survey.



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- MISO's capacity resource turnover continues to occur with coal unit contributions being primarily replaced by solar, wind, and battery facilities. Furthermore, generation installation delays result in uncertainty throughout the assessment timeframe. As a result of these factors, MISO is facing capacity shortfalls in the next five years.
- MISO's reduction in capacity resources since the *2023 LTRA* has primarily been in the coal fleet with a reduction of 6,200 MW in the first year of the assessment.
- MISO has continued the seasonal capacity auction construct and has found growing evidence of risk in non-peak (e.g., spring and fall) seasons. Countering the risk during these off-peak seasons requires more resources to be available, and this can result in less opportunity for generators to pursue their maintenance needs. During peak seasons when high levels of generator availability are expected, short-notice unplanned outages and higher forced outages could occur as a result of deferred maintenance and challenge reliability.

MISO Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	34,637	31,706	31,618	29,067	26,841
Coal*	27,450	24,362	23,203	17,977	16,744
Petroleum	3,065	3,058	3,060	3,050	3,050
Petroleum*	2,992	2,990	2,992	2,992	2,992
Natural Gas	63,051	62,977	62,616	62,394	62,009
Natural Gas*	62,576	61,543	62,396	62,394	62,009
Biomass	577	571	553	481	481
Solar	8,091	12,538	17,318	19,174	19,763
Wind	6,954	7,236	7,536	7,632	7,660
Conventional Hydro	1,527	1,527	1,527	1,527	1,527
Pumped Storage	2,528	2,528	2,578	2,578	2,578
Nuclear	11,027	11,127	11,127	11,127	11,127
Other	72	72	72	72	72
Battery	208	582	1,011	1,358	1,377
Total MW	132,159	134,892	140,263	139,973	138,018
Total MW*	124,423	126,048	131,562	128,826	127,864
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to MISO are removed from the resource projection where marked.					

MISO Assessment

Planning Reserve Margins

The planning reserves across the MISO footprint in the summer are projected to fall below reserve margin requirements as new generation coming on-line could be insufficient to make up for generator retirements and load growth. It is important to note that there is 56 GW of generation with signed generation interconnection agreements that are yet to come on-line as of July 5, 2024, so there is an opportunity to accelerate installation speeds. However, if resource additions remain at or near historically average levels (approximately 2.3 GW/year average over the last 3 years), PRMs in MISO will fall below the RML reserve margin requirements much faster. Summer PRMs with average resource additions are shown in **Figure 3** as **Reserve Margin-Avg Addition**.

Increased coordination between MISO and its members will be critical to ensuring reliability throughout this resource transition of integrating new intermittent resources and continuing to retire conventional resources. Resource adequacy is a key function of MISO, and the MISO annual planning resource auction (PRA) provides a mechanism for capacity sellers to provide resources that meet the needs of load-serving entities for each of the four seasons in the upcoming year. MISO's resource adequacy construct complements the jurisdiction that regulatory authorities have in determining the necessary level of adequacy.

Note: Capacity values for existing resources in tables on p. 41–42 reported by MISO reflect the Seasonal Accredited Capacity (SAC) for Summer. Adjustments and derates are applied to account for factors affecting expected resource output. The RML in the Demand, Resources, and Reserve Margins table on p. 41 is the Unforced Capacity (UCAP) RML, consistent with the reported capacity values.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The introduction of the seasonal PRA and inputs to the process provide more granularity and reliability planning for non-peak hour times during the year. In addition to that change, MISO conducts seasonal resource assessments evaluating generation availability, outage rates, and forecasted load variation across all four seasons. Refer to MISO's Resource Adequacy page.

Probabilistic Assessments

To establish RMLs that define the minimum reserve margins for resource adequacy, MISO performs its annual probabilistic Loss-of-Load Expectation (LOLE) Study per MISO tariff. In recent years, MISO improved its LOLE study modeling by including seasonal outage rates, correlated cold weather outage adder profiles, a probabilistic distribution of non-firm support, and 30 years of hourly wind and solar profiles. The LOLE study produces seasonal RMLs for the upcoming planning year that are used in MISO's planning resource auction. These RMLs are calculated such that they prescribe the minimum PRM that will meet an LOLE of 1 day in 10 years. For more information on the seasonal LOLE Study, visit: https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf.

MISO also performed a probabilistic analysis for the 2024 ProbA. Because MISO used the same model for both the ProbA and the LOLE study, transmission limitations were not included explicitly in the simulations. It is appropriate for MISO to make this assumption for the LOLE study and for determining capacity needs in the MISO system because MISO accounts for transmission limitations elsewhere in the resource adequacy process. However, for an adequacy assessment like the ProbA, the assumption can overvalue resource performance by not accounting for transmission constraints on the deliverability of energy resources. The resulting 2024 ProbA metrics in the table below can understate the risk of unserved energy and load loss.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	68.8	**0.000**	**0.000**
EUE (PPM)	0.108	**0.000**	**0.000**
LOLH (hours per year)	0.393	**0.000**	**0.000**
Operable On-Peak Margin	13.9%	**11.3%**	**11.3%**

* Provides the 2022 ProbA Results for Comparison

MISO is an elevated risk in the *2024 LTRA* because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. All-hours probabilistic studies of the MISO system performed apart from the 2024 ProbA show that shortfall risks can also occur during spring and fall in months that are not peak demand seasons for MISO. The 2022 NERC ProbA Regional Risk Scenario Sensitivity Case included seasonal forced-outage rates and correlated cold weather outages instead of annual average outage rates. MISO found that not only did EUE increase in this sensitivity, but it was also spread throughout the year. Since this study, MISO implemented enhancements to its LOLE study and PRA to address seasonal resource needs.

Demand

The peak demand forecast has increased from the *2023 LTRA* by close to 3 GW (~2.5%), and, while the load forecasts still vary across year to year, the load at the end of the study horizon is ~5 GW higher (~4%). Load-serving entities do not include DR resources in the load forecast, and MISO does not have much insight into the amount of electrification built into the load forecasts. There are other studies at MISO investigating electrification and transportation industry impacts to load forecasts

through the MTEP report. MISO contracted with Applied Energy Group (AEG) to evaluate the MISO footprint's electrification potential. This is documented in the report and has been utilized to update the MISO Futures Report.

Demand-Side Management

DR programs continue to play a significant role in providing capacity to MISO. DR is steady around 8 GW in the summer and 6.5 GW in the winter and is projected to remain constant during the study horizon. MISO's transition to seasonal auctions highlights accreditation of DR and availability during non-summer seasons.

Distributed Energy Resources

Behind-the-meter generation (BTMG) resources contribute about 4.2 GW of capacity across the study horizon, of which ~1.2 GW are distributed PV. MISO's transition to seasonal auctions highlights the availability of DERs across the four seasons, and MISO is working with stakeholders to derive adequate methods of aggregating, reporting, and allowing DER participation in MISO markets.

Generation

The departure of MISO's coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years. Solar continues to rise in capacity contributions with a growth of 1,200 MW since the *2023 LTRA* and growth of 3,200 MW in the first year of the study.

There are ~56 GW installed capacity (ICAP) of generation (predominantly solar and battery) with signed generation interconnection agreements in MISO that are projected to come on-line over the next few years. There have been some supply chain and tariff issues that have delayed the commercial operation of these resources.

Due to the large size in the MISO interconnection queue, in the 2022 LTRA (similarly to the OMS-MISO Survey), prospective generation in the queue gets multiplied by a factor based on the study phase and likelihood of that resource coming on-line and gets added into the footprint over time. This reduction is utilized to minimize the impact of prospective generation projects that will not come to fruition through the queue cycle. MISO continues to pursue queue reform efforts to expedite the process by ensuring projects being studied are of adequate certainty.

Transmission

The MISO Transmission Expansion Plan (MTEP) 2021 included the Long-Range Transmission Plan (LRTP) tranche 1 projects totaling $10.3 billion in investment for reliability and economic benefits estimated at $23–52 billion across the MISO footprint while also facilitating the integration of ~53 GW of new resources. In MTEP22, $4.3 billion in transmission projects were approved with $550 million going toward integrating new resources, $550 million going toward baseline reliability projects, and the age and condition category for the rest. MTEP23 includes a further $9 billion investment into the MISO footprint to address the local needs of the region. MISO is also pursuing LRTP tranche 2 with an expected investment of $18-23 billion to implement a 765 kV backbone into the northern portion of the footprint. These projects are expected to be included as part of MISO's MTEP24 project portfolio. In MTEP24, $6.7 billion in transmission projects have been submitted for board approval. MISO is also pursuing LRTP tranche 2.1 with an expected investment of $21.8 billion to implement a 765 kV backbone into the midwestern portion of the footprint. Tranche 2.1 brings reliability and economic benefits estimated at $51.7–101 billion across the MISO Midwest footprint, facilitating integration of ~115.7 GW of new resources.

Energy Storage

MISO's energy storage resources are still primarily in the future with only 84 MW of on-line storage. The MISO interconnection queue does have a significant amount of energy storage upcoming, but these are primarily Tier 3 resources at present.

Capacity Transfers

MISO benefits from significant transfer capacity with neighboring assessment areas due to the geographic location. MISO and SPP continue to finalize the Joint Targeted Interconnection Queue (JTIQ) portfolio to resolve the binding constraints that have traditionally delayed the interconnection process. MISO's utilization of capacity transfers is identified in the LOLE report and memorialized through the MISO PRA.

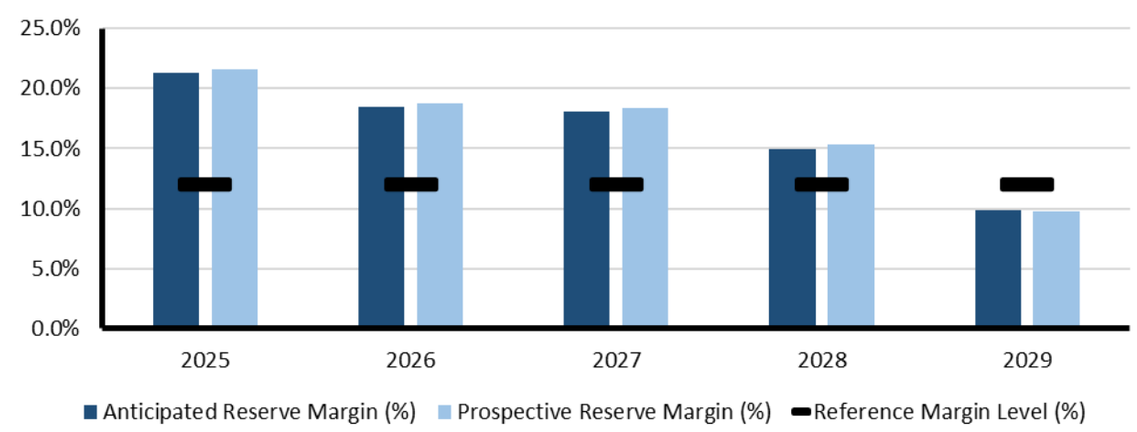


MRO-Manitoba Hydro

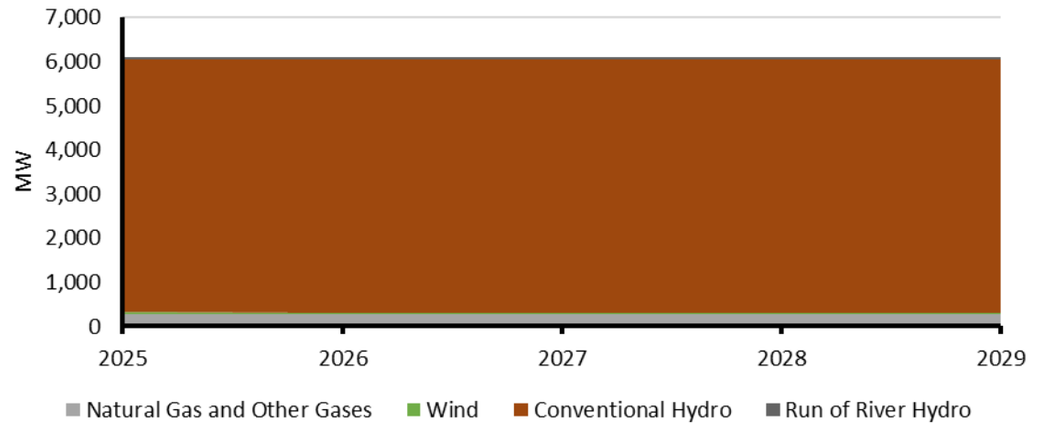
Manitoba Hydro is a provincial Crown Corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 616,000 electric customers in Manitoba and provides approximately 296,000 customers with natural gas in southern Manitoba. The service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter-peaking. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	4,797	4,923	4,968	5,037	5,268	5,366	5,427	5,486	5,556	5,629
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,797	4,923	4,968	5,037	5,268	5,366	5,427	5,486	5,556	5,629
Additions: Tier 1	30	51	64	64	64	64	64	64	64	64
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-113	-113	-93	-167	-172	-565	-565	-565	-565	-565
Existing-Certain and Net Firm Transfers	5,786	5,780	5,800	5,726	5,721	5,328	5,328	5,328	5,328	5,328
Anticipated Reserve Margin (%)	21.3%	18.4%	18.0%	15.0%	9.8%	0.5%	-0.6%	-1.7%	-2.9%	-4.2%
Prospective Reserve Margin (%)	21.6%	18.8%	18.4%	15.3%	9.8%	0.5%	-0.6%	-1.7%	-3.0%	-4.2%
Reference Margin Level (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The electricity demand forecast in the province of Manitoba has increased since the *2023 LTRA*, driven by expected economic activity and adoption of EVs. Resource projections have not changed significantly.
- The ARM falls below the RML of 12% beginning in Winter 2029–2030 due to load growth and the reduction of winter import capacity transfers. Manitoba Hydro is performing analysis to inform its integrated resource plan and support future decisions for resources.

MRO-Manitoba Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**
Natural Gas	278	278	278	278	278
Wind	52	31	31	31	31
Conventional Hydro	5,705	5,726	5,739	5,739	5,739
Conventional Hydro*	5,705	5,726	5,739	5,739	5,721
Run of River Hydro	856	856	856	856	856
Total MW	6,094	6,094	6,107	6,107	6,107
Total MW*	6,094	6,094	6,107	6,107	6,089
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

MRO-Manitoba Hydro Assessment

Planning Reserve Margins

The winter ARM falls below the Reference Margin Level of 12% in 2029–2030. No resource adequacy issues are anticipated until Winter 2029–2030. A Tier 1 project to replace eight older and smaller hydro units is being planned for the Pointe du Bois Generating Station. The Pointe du Bois Renewable Energy Project (PREP), approximately 50 MW, replaces the original hydro units that were mothballed or retired based on economics/end of life after about 100 years of operation. No Tier 2 or Tier 3 resources have been assumed to come into service during the assessment period.

The ARM falls below the Reference Margin Level of 12% beginning in Winter 2029–2030 due to net load growth and the reduction of winter import capacity transfers. Manitoba Hydro's Integrated Resource Plan was published in Summer 2023. Further analysis is underway and will help inform Manitoba Hydro's future resource decisions for resources in the 2029 timeframe.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Under normal water conditions, over 95% of the generation in Manitoba Hydro's system is from renewable energy—primarily hydro generation and wind generation. As the operator of a predominantly hydro system, Manitoba Hydro frequently performs an all-hours energy adequacy analysis of the near-term through seasonal time periods to manage reservoir energy storage and meet system demand. Additionally, Manitoba Hydro conducts specific analyses to determine short-term storage and minimum flow requirements for maintaining Manitoba and extra-provincial resource adequacy obligations. As there are modest levels of wind and solar on the Manitoba Hydro system, the resource adequacy risk on the Manitoba Hydro system over the next five years and under normal water conditions is expected to coincide with peak demand hours**.**

There are a number of influencing factors associated with Manitoba Hydro's resource adequacy performance, such as the water resource conditions, energy and capacity exchanges with neighboring jurisdictions, forecast load level, uncertainties in load forecast and load variation profiles, demand responses, wind penetration, and generation fleet availability. Most of Manitoba Hydro's generating facilities are use-limited or energy-limited hydro units. The annual energy output of these facilities is mostly dependent on the availability of the water resource. In the 2024 ProbA, Manitoba Hydro examines the impact of the most significant factor over the long run—variations in water conditions.

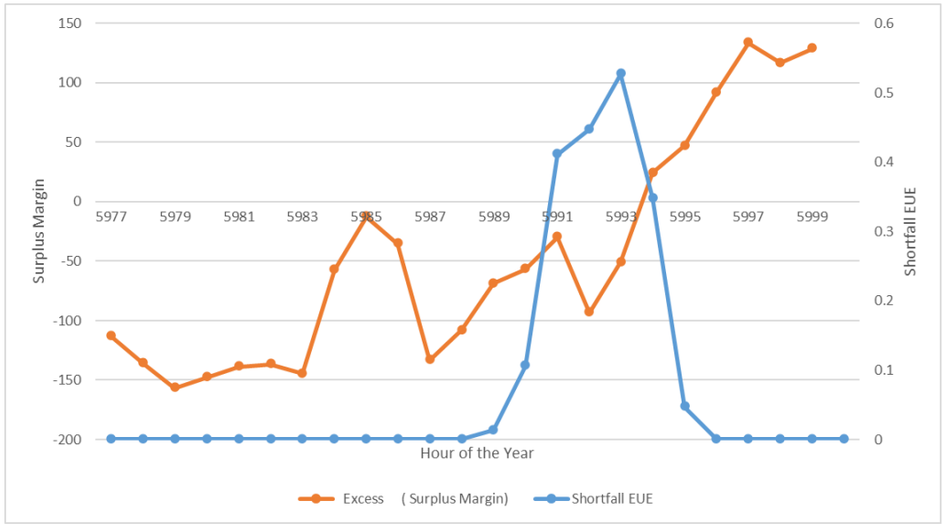
Nonzero LOLH and EUE are observed for both reporting years of 2026 and 2028 and shown in the table below. The LOLH and EUE indices are higher compared to the 2022 assessment mainly due to the increase in the forecast peak demand. Water flow conditions of 10th percentile or lower tend to increase the LOLH and EUE. As a small winter-peaking system on the northern edge of a large summer peaking system (MISO), there generally is assistance available, particularly in MISO's off-peak hours, to provide energy to supplement hydro generation in low-flow conditions in winter. Management of energy in reservoir storage in accordance with good utility practice provides risk mitigation under low water flow conditions.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	7.23	**4.711**	**68.870**
EUE (PPM)	0.29	**0.176**	**2.504**
LOLH (hours per year)	0.01	**0.059**	**0.914**
Operable On-Peak Margin	13.5%	**18.8%**	**15.6%**

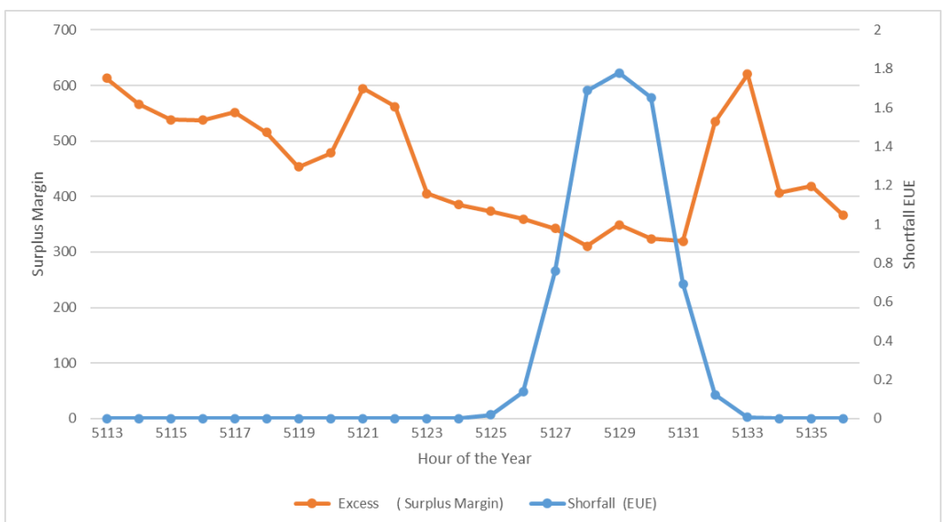
* Provides the 2022 ProbA Results for Comparison

The Monthly EUE and LOLH for 2026 and 2028 show that the highest LOLH and EUE contribution are from July and November, respectively, for 2026 and 2028.

The two graphs below show the hourly energy availability on the Manitoba Hydro system during the ProbA's highest risk days in 2026 and 2028. Surplus energy and shortfall EUE are plotted for the day when the highest loss of load event happens in the ProbA analysis. The Probability Weighted Average (PWA) surplus margin is negative, which indicates possible loss of loads for 2026. However, the PWA surplus energy is higher for 2028 during the day when the highest loss of load event is observed. This is because the surplus is an average for different water year data and the average surplus may not represent the event when loss of load occurs.

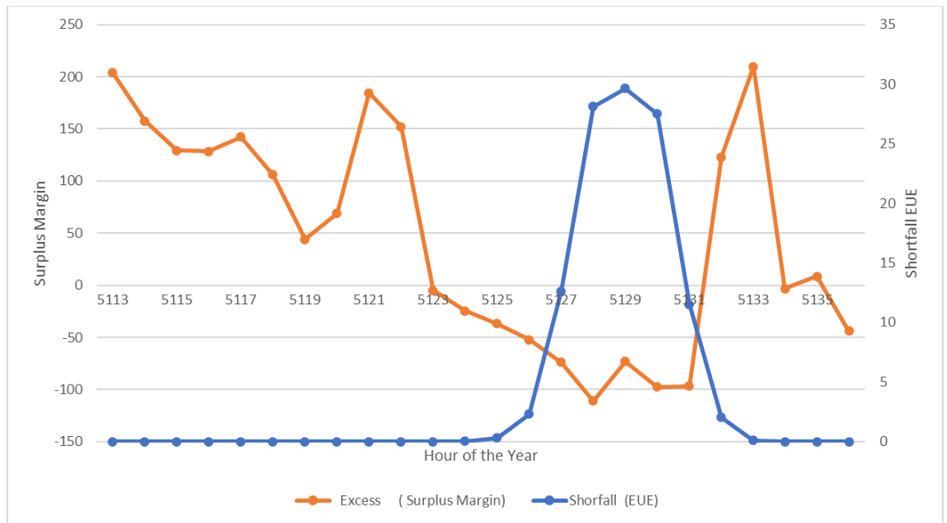


Hourly PWA Surplus Margin and Shortfall EUE for 2026 Representative Risk Day (Summer)



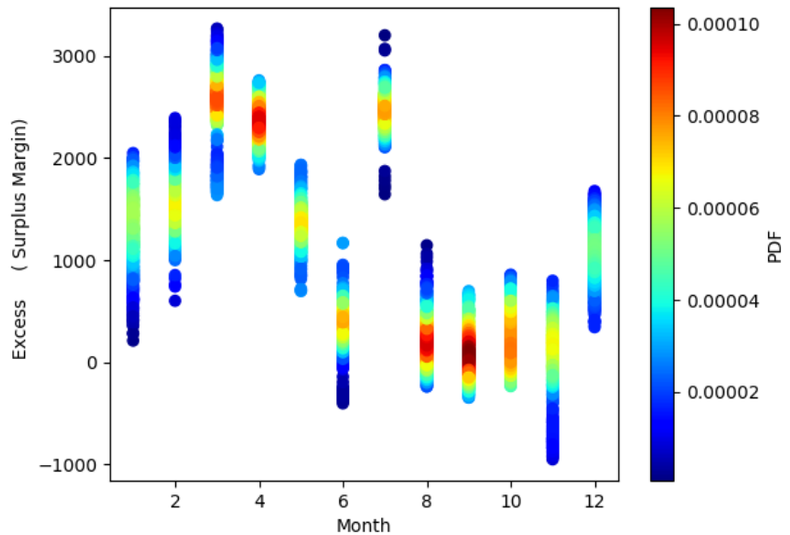
Hourly PWA Surplus Margin and Shortfall EUE for 2028 Representative Risk Day (Summer)

The figure below shows the surplus margin and shortfall EUE for 2028 under extreme drought conditions. It can be seen that the loss-of-load event occurs when the surplus margin becomes negative. This surplus energy shown in the figure is the average value for this hour for the entire simulation. It may not represent each individual loss-of-load event during simulation. By plotting the hourly surplus and unserved energy for the low-water years, it is possible to see what risk periods are likely to emerge during extreme drought.



Hourly PWA Surplus Margin and Shortfall EUE for 2028 Representative Risk Day (Summer) During Extreme Drought Condition

The scatter plots of surplus energy vs. month for 2026 and 2028 are shown in the figures below. In the months of June and August to November, the PWA surplus energy is relatively lower compared to the other months due to less import from MISO. The PWA surplus energy in July 2026 is high due to higher hydro energy availability for July. However, since PWA is the result of averaging, positive surplus energy does not mean that there will be no loss-of-load events.



PWA Surplus Energy Versus Month for 2026

Demand

Manitoba Hydro's load-growth forecast is up around 3.2% over the assessment period in comparison with the forecast used for the *2023 LTRA*. Factors considered in load-growth projections include economic activity, EV adoption, and demand-side management programs in Manitoba operated by Efficiency Manitoba. EV adoption in Manitoba is being driven in part by proposed federal regulations that are expected to require that at least 20 percent of new vehicles sold in Canada will be zero-emission by 2026, at least 60 percent by 2030, and 100 percent by 2035.

Manitoba Hydro is anticipating load growth of 1.3% over the last half of the assessment period. Limited surplus firm generation resources (resource adequacy) have the potential to slow the connection of very large new industrial loads. In order to limit load growth, Manitoba Hydro has been directed by the Province of Manitoba to suspend processing of cryptocurrency load connections until 2026.

Demand-Side Management

Manitoba Hydro currently does not have any form of directly controllable and dispatchable DR programs. Manitoba Hydro does have an indirectly controllable and dispatchable DR program called the Curtailable Rate Program.

The Curtailable Rate Program provides approximately 160 MW of load reduction through up to 16 load curtailments of 4¼ hours each on five minutes notice. The program is intended for peak load management. In addition, one product provides 50 MW of contingency reserves, also on five minutes' notice.

The terms and conditions of the Curtailable Rate Program were updated in August 2023 to require an annual curtailment test, increase the number of possible curtailments, extend the notice period for conversion to firm service, and make minor editorial changes.

Distributed Energy Resources

Manitoba is not currently experiencing large additions of wind and solar resources being seen in other regions; hence, emerging reliability issues arising from such large wind and solar resource additions are not anticipated in the next five years. Additions of energy storage resources in the next 10 years are not anticipated at this time. There is a potential for significant solar DER resources in the latter half of the assessment period, and plans are being developed to study the impacts on the Manitoba Hydro system. The potential for future solar DER may be dependent on solar PV subsidies and/or incentives.

Generation

Manitoba Hydro is monitoring federal and provincial policy/strategies/regulations related to electricity/energy. The Canadian federal government is considering significant carbon emission regulations. Through Environment and Climate Change Canada, it is taking multiple steps to develop clean electricity regulations that aim for Canadian electricity generation to achieve net-zero greenhouse gas emissions by 2035 by requiring generating units to meet a stringent emissions intensity standard (measured in tons CO2 equivalent per GWh) and pay a price for any remaining emissions. The proposed regulations are still in development and not proposed to be fully implemented until 2035, so it is too early to determine any potential impacts. The Province of Manitoba is developing a provincial energy strategy/policy which may be released in Fall 2024. As details are not yet available, it is too early to determine any potential impacts.

Energy Storage

Manitoba Hydro currently has no energy storage resources, and none have been committed to over the next 10-year period.

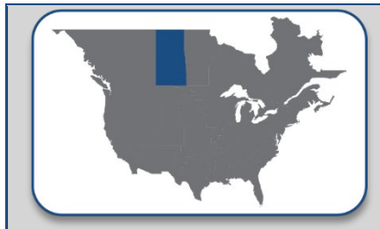
The hydro generation resources, while not storing electricity directly, do store water in a reservoir for conversion to electricity and have been in use for over 100 years. For most hours of the year, the only dispatchable resources online are hydro generation resources which therefore serve most operational, reliability, and economic functions.

Capacity Transfers

Manitoba Hydro has coordination and tie-line agreements with neighboring assessment areas, such as MISO, SaskPower, and the IESO. In accordance with these agreements, planning- and operating-related issues are discussed and coordinated through respective committees. In addition to this planning and operating committee work, Manitoba Hydro engages with the neighboring utilities of Minnesota Power, Xcel Energy, Otter Tail Power, Minnkota Power Cooperative, SaskPower, and Hydro One regularly to share information, discuss issues, and coordinate activities. Manitoba Hydro also coordinates planning studies (for example, transmission service request studies and requests for generation interconnections) with its neighboring assessment areas. In addition, capacity transfers are verified from a resource adequacy perspective with adjacent regions/entities. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts but only in extreme conditions occurring simultaneously.

Transmission

Manitoba Hydro has identified aging components of its HVdc system as a potential reliability issue that is unique to the assessment area. The concern is that the oldest HVdc system components could be approaching end of life. Studies have been initiated to study/evaluate modernization options and alternatives. The studies and procurement of replacement equipment could take up to 10 years to implement based on the current HVdc market capability. There is currently spare capacity on the HVdc system, and the end-of-life failure of a single pole would not create reliability issues. The further end-of-life failure of a second pole, while believed to be a very low probability, has the potential to create reliability concerns under peak winter loads if mitigation measures are not implemented. Mitigation measures to minimize the likelihood of experiencing this quantity of long-term outages are being actively pursued.

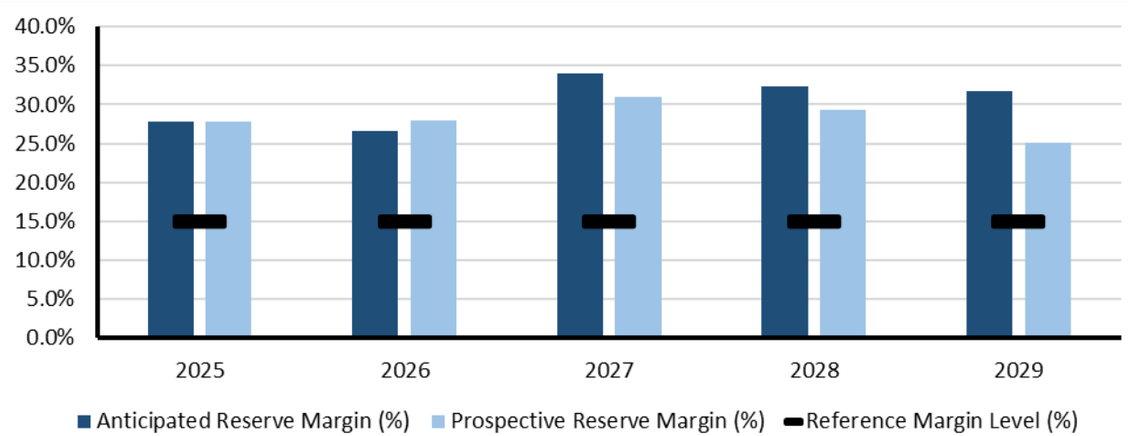


MRO-SaskPower

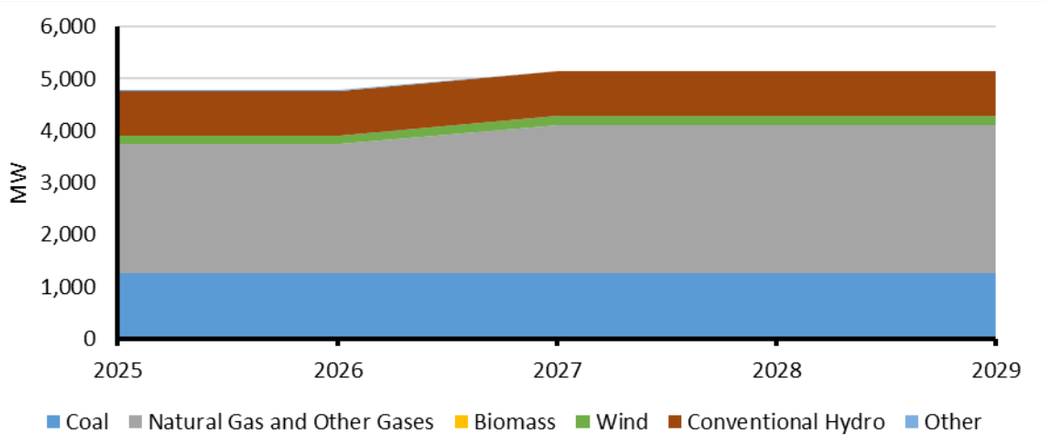
MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles), with a population of 1.2 million and approximately 550,000 customers. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown Corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	3,917	4,025	4,149	4,189	4,210	4,242	4,271	4,315	4,359	4,408
Demand Response	72	72	72	72	72	72	72	72	72	72
Net Internal Demand	3,845	3,953	4,077	4,117	4,138	4,170	4,199	4,243	4,287	4,336
Additions: Tier 1	507	507	883	883	883	883	883	883	883	883
Additions: Tier 2	0	55	175	175	928	928	928	928	928	928
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	290	290	315	315	315	315	315	315	315	315
Existing-Certain and Net Firm Transfers	4,407	4,497	4,582	4,566	4,566	4,489	4,490	4,490	4,552	4,566
Anticipated Reserve Margin (%)	27.8%	26.6%	34.0%	32.4%	31.7%	28.8%	28.0%	26.6%	26.8%	25.7%
Prospective Reserve Margin (%)	27.8%	28%	31.0%	29.3%	25.1%	22.3%	20.8%	19.5%	19.8%	18.7%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- SaskPower's ARM is above the RML throughout the assessment period. No resource adequacy issues are anticipated.
- Saskatchewan is adding approximately 1,064 MW of generation under Tier 1 within the next five years. This includes a 200 MW wind generation facility, two new 377 MW gas generation facilities, and the expansion of two existing natural gas facilities totaling 90 MW. The remaining capacity addition comes from geothermal and flare gas.

MRO-SaskPower Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Coal	1,249	1,249	1,249	1,249	1,249
Coal*	1,249	1,249	1,088	1,088	188
Natural Gas	2,487	2,487	2,863	2,863	2,863
Biomass	3	3	3	3	3
Wind	164	164	162	162	162
Conventional Hydro	856	856	856	856	856
Other	22	17	17	1	1
Total MW	4,781	4,775	5,150	5,134	5,134
Total MW*	4,781	4,775	4,989	4,973	4,073
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

MRO-SaskPower Assessment

Planning Reserve Margins

Saskatchewan uses a criterion of 15% as the reference reserve margin and has assessed its PRM for the upcoming 10 years considering the summer and winter peak hour loads, available existing and anticipated generation resources, firm capacity transfers, and available demand response for each year. Saskatchewan's ARM ranges from approximately 19% to 34% and does not fall below the Reference Margin Level.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Saskatchewan performs energy assessments using probabilistic methods to inform the area's resource adequacy requirements. Saskatchewan evaluates non-peak hour risks and diminishing capacity credits associated with higher penetration levels of VERs as part of the long-term planning process.

Results of the 2024 ProbA are provided in the table below. Based on the deterministic calculations within this assessment, Saskatchewan's ARM is 27.8% and 34.0% for years 2026 and 2028, respectively. Since the 2022 ProbA, the reported forecast reserve margin for 2026 has remained consistent. The minor variation in the reserve margin is due to a slight change in the schedule of generator outages. EUE is also comparable to the 2022 ProbA, with some variation attributed to updated hydro energy dispatch, which is able to reduce the EUE in the months where it was highest in the prior ProbA.

Base Case Summary of Results			
	2026*	2026	2026
EUE (MWh)	117.0	**75.641**	**8.553**
EUE (PPM)	4.4	**2.807**	**0.300**
LOLH (hours per year)	0.9	**0.547**	**0.078**
Operable On-Peak Margin	24.6	**24.4%**	**30.5%**

* Provides the 2022 ProbA Results for Comparison

Saskatchewan does not anticipate resource adequacy issues during its off-peak hours. Currently, its resource mix consists of baseload and fast ramping generation resources, with little penetration of VERs. The main factor contributing to EUE is the amount of planned generator outages. When these short-term reliability issues are identified in advance, they can be mitigated by rescheduling the maintenance. The hourly EUE heat maps in the following figures show that risk of unserved energy is at its highest in the summer months. Risk can also be found in months before or after summer and be driven by unseasonable temperatures driving above-normal demand that coincides with generator maintenance periods. Winter risks of shortfall are associated with extreme cold weather and unexpected generator outages.

Hourly EUE Heat Map : 2026

EUE	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-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Feb-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mar-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apr-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
May-26	1.2	1.2	1.1	1.2	1.2	1.3	1.3	1.3	1.4	1.5	1.6	1.8	1.8	1.7	1.7	1.6	1.6	1.6	1.5	1.5	1.5	1.6	1.5	1.3
Jun-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jul-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.1	0.0	0.0	0.0	0.0	0.0
Aug-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.0
Sep-26	0.5	0.6	0.6	0.6	0.6	0.5	0.6	0.7	0.7	0.8	0.9	1.2	1.2	1.3	1.4	1.5	1.5	1.6	1.4	1.5	1.7	1.3	1.0	0.7
Oct-26	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.4	0.3	0.3
Nov-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Dec-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.1	0.1

Hourly EUE Heat Map : 2028

EUE	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-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feb-28	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mar-28	0.0	0.0	0.0	-	-	-	-	0.0	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apr-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
May-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jun-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Jul-28	0.0	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
Aug-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sep-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oct-28	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1
Nov-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Dec-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0

Hourly EUE Heat Maps (in MWh)

Demand

Saskatchewan experiences its peak-season in the winter. Saskatchewan's system peak load forecast is based on econometric variables, weather normalization, and individual level forecasts for large industrial customers. The average annual summer and winter peak demand growth is expected to be approximately 1.35% throughout the assessment period.

Demand-Side Management
Saskatchewan's EE and energy conservation programs include incentive-based and education programs focusing on installed measures and products that provide verifiable, measurable, and permanent reductions in electrical energy, and demand reductions during peak hours.

Saskatchewan's DR consists of contracts with industrial customers for interruptible load based under conditions specified in demand response programs. The first of these programs provides a curtailable load, currently up to 72 MW, with a 12-minute event response time. Other programs are in place providing access to additional curtailable load requiring up to two hours notification time.

Distributed Energy Resources
The current BTM DER installed capacity in Saskatchewan is approximately 50 MW, which includes approximately 48 MW of solar PV and the remaining approximately 2 MW of distributed wind projects. An additional 25 MW of DER solar PV are expected to be added in the next five years. BTM DER installations are incorporated into the load forecast models, which are used in supply and transmission planning study models.

Small power producers contribute an additional 5 MW installed DER capacity (non-BTM) in Saskatchewan. There is currently an existing 8 MW and a potential for up to 20 MW of DERs being added in the next 2 years based on the currently approved Power Generation Partner program. These projects are included as generation additions, but currently their capacity is not considered in reliability planning.

Generation
Saskatchewan is adding approximately 1,064 MW into its resource mix of generation under the Tier 1 category within the next five years. The includes a 200 MW wind generation facility, expansion of two existing natural gas facilities totaling 90 MW, two new natural gas facilities totaling 754 MW, 15 MW of flare gas generation, and 5 MW of geothermal generation.

Under Tier 2, over 1,717 MW of new generation is projected in the assessment period. This includes 754 MW of natural gas, 600 MW of wind generation, 300 MW of utility-scale solar generation, and 63 MW of co-generation.

Generating resources being planned as Tier 2 and Tier 3 will replace generators planned for retirement prior to deactivation. Therefore, Saskatchewan is not expecting any long-term reliability impacts due to generation retirements.

Energy Storage
SaskPower currently has its first battery storage system, a 20 MW/20 MWh unit, under commissioning. There are plans to expand this site by an additional 60 MW/60MWh capacity. The prevalent use for the planned energy storage is to provide regulating reserve, peak capacity and energy reduction, net demand ramping control, reactive power/voltage control, primary frequency control, and blackstart.

Capacity Transfers
SaskPower has three interfaces with its neighboring areas. The interface with Manitoba is the largest of the three interfaces and is the only interface with long-term firm contracts. Capacity transfers from Manitoba would be limited in the event of a prior outage of tie lines between SaskPower and Manitoba Hydro, as well as nearby transmission facilities supporting the interface. This could only impact reliability if it is coincident with the extreme winter or summer peak demand and a prior outage of one or more larger generating units in Saskatchewan. Risk mitigation is in place through SaskPower's emergency operating procedure that will allow one or more measures such as short-term imports from other available interfaces (for example Alberta or SPP), initiating demand response and short-term load shedding.

Transmission
SaskPower's major transmission projects in the first five years of the assessment period are related to the interconnection expansion with SPP and the 650 MW of new transmission service. This includes two new international power lines between Saskatchewan and North Dakota. Within Saskatchewan, a total of approximately 180 kilometers of new 230 kV lines, a new 230 kV transmission station, expansion of several existing transmission stations, and installation of two phase-shifting transformer interfaces and two static var systems are being added.

The remaining other transmission projects (approximately 460 circuit kilometers) are under the planning and conceptual phase in the 5-to-10-year planning horizon. These projects are driven by load growth, new generation additions, and reliability needs.

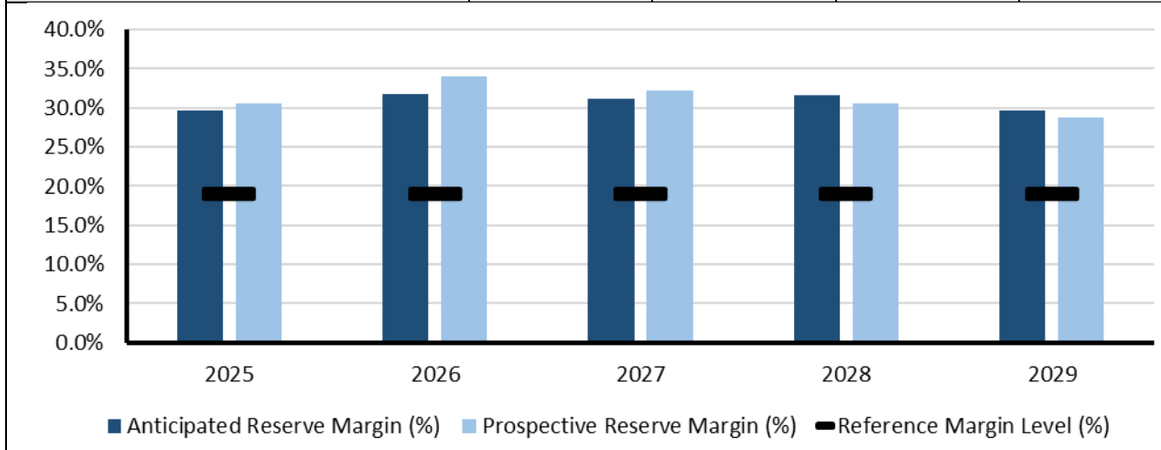


MRO-SPP

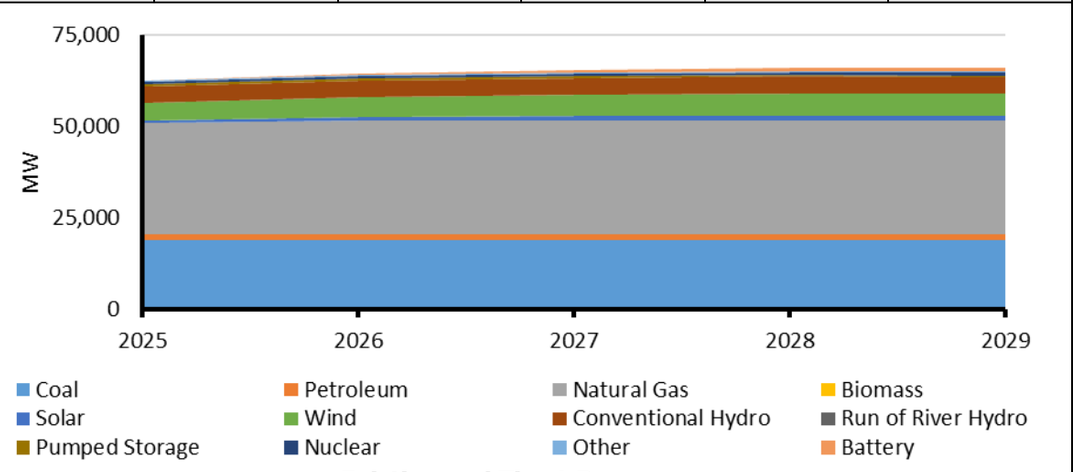
The Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	55,669	57,171	59,031	59,764	60,596	61,963	62,490	63,287	63,764	64,172
Demand Response	1,463	1,771	2,057	2,124	2,172	2,222	2,259	2,465	2,467	2,472
Net Internal Demand	54,206	55,400	56,975	57,640	58,424	59,741	60,231	60,822	61,297	61,700
Additions: Tier 1	2,123	4,966	6,750	7,843	7,957	7,957	7,957	7,957	7,957	7,957
Additions: Tier 2	1,239	2,454	2,756	2,756	2,756	2,756	2,756	2,756	2,756	2,756
Additions: Tier 3	6,823	16,770	22,655	28,948	28,948	28,948	28,948	28,948	28,948	28,948
Net Firm Capacity Transfers	-1,097	-1,077	-1,136	-1,131	-1,131	-1,131	-1,131	-1,133	-1,133	-1,133
Existing-Certain and Net Firm Transfers	68,157	68,039	67,981	67,984	67,799	67,749	67,253	67,175	67,055	67,094
Anticipated Reserve Margin (%)	29.7%	31.8%	31.2%	31.6%	29.7%	26.7%	24.9%	23.5%	22.4%	21.6%
Prospective Reserve Margin (%)	30.6%	34.1%	32.2%	30.6%	28.7%	25.2%	23.3%	22.0%	20.6%	19.6%
Reference Margin Level (%)	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- There are over 8 GW of coal and gas-fired generators that have indicated they plan to retire over the next 10 years in SPP. Without sufficient dispatchable generation, SPP can experience energy shortages when output from wind resources is low.

MRO-SPP Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	18,952	18,952	18,919	18,919	18,919
Coal*	17,934	16,647	16,614	14,062	14,062
Petroleum	1,629	1,629	1,631	1,631	1,631
Petroleum*	1,629	1,629	1,575	1,575	1,575
Natural Gas	30,471	31,098	31,098	31,098	31,098
Natural Gas*	29,896	30,220	29,924	29,812	29,812
Biomass	20	20	20	20	20
Solar	495	864	1,149	1,283	1,283
Wind	4,974	5,456	5,928	6,117	5,909
Conventional Hydro	4,526	4,541	4,573	4,605	4,628
Pumped Storage	472	472	472	472	472
Nuclear	769	769	769	769	769
Other	281	281	281	281	281
Battery	41	290	555	930	1,044
Total MW	62,630	64,370	65,392	66,124	66,053
Total MW*	61,037	61,188	61,858	59,925	59,855
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to SPP are removed from the resource projection where marked.					

MRO-SPP Assessment

Planning Reserve Margins

The Existing-Certain and Net Firm Transfers Reserve Margin for the SPP assessment area is projected to fall below the current coincident summer season RML of 19% in 2027. The current summer season reserve margin target for SPP is 15%, but that is based on the non-coincident peak demand of load-responsible entities (LRE) in the SPP assessment area. For purposes of NERC assessments, the 15% target is converted, along with forecasted demand values, to an SPP coincident peak representation based on the latest calculated diversity factor. This results in an RML of 19%. Based on resources submitted in the ARM calculation, including the impact of retirements, SPP is forecasted to be above the 19% RML for the 10-year horizon.

Like the generation unavailability scenario in NERC's *2024 Summer Reliability Assessment*, SPP shows the potential to utilize all the current projected capacity and there could be times of capacity shortfall based on performance impacts during high-load periods. While the potential to all available capacity has a lower probability, the assumptions and projections are based around historical unavailability during peak periods. Current LTRA projections are based on the latest resource adequacy data submittals, which are provided by the LREs and Generator Owners in SPP.

SPP performs a biennial LOLE study to establish a reserve margin target such that the LOLE for the applicable planning year (3- and 6-year study) does not exceed 1 day in 10 years, or 0.1 day per year. The target is determined using probabilistic methods by altering capacity through the application of generator forced outages and forecasted demand with load uncertainty to ensure that the LOLE does not exceed 0.1 day per year.

SPP's 2023 LOLE study results indicate that separate PRMs and capacity requirements are needed for the summer and winter seasons to recognize the seasonal balance of risk. Also, as colder temperature outages increase with the incorporation of additional wind and solar resources, the loss-of-load risk shifts to the winter season. Due to the shift in seasonal risk, it would be appropriate to consider a maximum LOLE threshold for the winter season or incorporation of an EUE reliability metric to complement the LOLE metric.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

As the resource mix continues to change from a standard base load conventional thermal and hydro resources to VERs and short-term energy storage resources (ESR), SPP is incorporating energy adequacy metrics (i.e., EUE) in the determination of PRMs, RMLs, additional reliability policies, and resource accreditation enhancements.

SPP will begin performing a yearly energy adequacy assessment and assessment of reliability attributes (inertia, primary frequency response, ramp, regulation, contingency reserves, voltage and reactive support capability, fuel assurance, flexibility, and blackstart capability). Results of the analysis will be presented annually to SPP stakeholders. The results will also be used to identify needs for new market products, changes to market functionality, or changes to resource adequacy policies and requirements.

The 2024 ProbA performed for the NERC LTRA used assumptions and methods that reflect SPP's Loss of LOLE studies. Results are shown in the following table.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.84	0.00	6.61
EUE (PPM)	0.00	0.00	0.02
LOLH (hours per year)	0.00	0.00	0.01
Operable On-Peak Margin	19.6%	19.5%	16.0%

*Provides the 2022 ProbA Results for Comparison

With the current SPP fleet, there was no loss of load for the 2026 study that included Tier 1 resource additions and 600 MW in generator retirements. The 2028 analysis included both Tier 1 and Tier 2 resource additions and 2,700 MW in generator retirements. The result was a small amount of EUE (6.61MWh) and LOLH (0.01hr/year). The loss of load/hour occurred mostly during the summer season (0.007hr/yr), while the winter season had 0.0004hr/yr. SPP is a summer-peaking region, and the results also supported that. The demand was highest in the afternoons between 13:00 and 19:00 during July and August.

Study improvements for 2024 from the previous NERC ProbAs include additional weather years, seasonal forced-outage modeling, and incremental cold weather outages.

SPP uses the Strategic Energy & Risk Valuation Model (SERVM) for the ProbA. It is a production-cost modeling tool that uses the Monte Carlo method to solve LOLE. Each weather year was simulated 300 times to simulate a multitude of random forced outage draws. Taking 300 draws for each weather year (43) and multiplying by 8,760 hours gets to a total of over 113 million simulated hours, from 1980 to 2022. Each iteration was performed on an 8,760-hour basis.

The study input model consisted of multiple modeling assumptions including multiple historical weather years (1980–2022); hourly load, solar, and wind profiles; load forecast uncertainty; random forced outages draws and variability; physical and economic resource parameters; resource retirements; future resource additions; zonal transmission limitations; and incremental conventional resource forced outages due to extreme cold temperature.

The generating resources modeled in the Probabilistic Assessment reflect the data supplied in the *2024 LTRA*. Existing and projected resources were included in the Probabilistic Assessment along with reported confirmed retirements. As mentioned previously, wind and solar resources, as well as historical weather years, were modeled at historical hourly values using 2012 to 2022 weather years. There were six study zones, and SPP modeled a projected 8,760 hourly demand profile for each area to provide load variability and volatility for chronological hours during simulation. Each local resource zone was modeled with an import and export limit based on a separate power flow transfer analysis. SPP used unit-specific outage rates within the analysis based on NERC Generation Availability Data System (GADS) data from 2015 to 2022. External assistance only included firm contracts from external entities with firm transmission service.

Demand

SPP peak load occurs during the summer season; the 2024 net internal demand forecast is projected to peak at 53,094 MW, which is projected to increase compared to the previous year's LTRA forecast for the 2022 summer season. The diversity factor used to convert the non-coincident peak demand forecast to an SPP coincident peak demand forecast was consistent with the ~3.5% applied in the *2023 LTRA*. SPP forecasts the coincident annual peak growth based on member submitted data over the 10-year assessment timeframe. One risk that SPP has noted is that the aggregated noncoincident demand forecast submitted by members in recent years, which is based on a 50/50 forecast and is weather normalized, is tracking at a lower demand level than what the BA has observed.

Demand-Side Management

SPP's energy efficiency (EE) and conservation programs are incorporated into the reporting entities' demand forecasts. There are no known impacts to the SPP assessment area's long-term reliability related to the forecasted increase in EE and DR across the assessment area. In addition, SPP is constructing a new policy to more appropriately categorize DR based on the flexibility of the program, which will ultimately be reflected in the accreditation process.

Distributed Energy Resources

The SPP Model Development, Economic Studies, and Supply Adequacy working groups are developing policies and procedures around DERs. SPP resource adequacy implemented policies for DERs that mandate certain testing, reporting, and document requirements for resources and programs not registered in the SPP Integrated Market. Accreditation methodology policies are being constructed and are planned to be approved in late 2024.

Generation

SPP currently has approximately 900 MW of installed solar generating facilities. In the ARM calculation, SPP is reporting nameplate capacity of approximately 11 GW of Tier 1, 2, and 3 wind resources, approximately 18 GW of Tier 1, 2, and 3 solar resources, approximately 9.8 GW of Tier 1, 2, and 3 battery resources and approximately 2.7 GW of Tier 1, 2, and 3 gas resources.

In 2024, SPP filed conventional based performance accreditation and effective load carrying capability (ELCC) methodology for wind and solar resources. The goal is for these policies to become effective in the 2026/2027 timeframe for both the summer and winter seasons.

There are concerns of drought conditions impacting the Missouri River and other water sources for generation resources that rely on once-through cooling processes. Low water can impact the generation's capacity output and reduce its ability to support congestion management and serve load. An additional concern could be the impact of river conditions on coal shipments, which could cause generators to run at a derated level to conserve supplies.

Energy Storage

Currently, SPP is studying approximately 17,000 MWs of energy storage and hybrid resource projects in the generator interconnection queue process. There are approximately 50 MWs of energy storage under contract by SPP members. These resources are being modeled as generation in the planning assumptions both near and long term.

Capacity Transfers

The SPP assessment area coordinates with neighboring areas to ensure that adequate transfer capabilities will be available for capacity transfers. On an annual basis during the model build season, SPP staff coordinate the modeling of transfers between Planning Coordinator footprints. The modeled transactions are fed into the models created for the SPP planning process.

SPP and ERCOT executed a Coordination Plan that superseded the prior coordination agreement. The Coordination Plan addresses operational issues for coordination of the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers (BLT), and switchable generation resources (SWGR). Under the terms of the Coordination Plan, SPP has priority to recall the capacity of any SWGRs that have been committed to satisfying the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff. Annually, SPP and ERCOT update the

Coordination Plan based on the latest discussions and business decisions, and it was updated in June 2024.

Transmission

In the 2023 ITP Assessment, SPP approved 44 transmission projects, including 150 miles of new transmission. Additionally, the study calls for 93 miles of transmission to be rebuilt.

SPP is observing a number of transmission projects that are currently delayed. SPP is actively tracking these projects and discussing them throughout its stakeholder process. Many delays are driven by supply chain issues or increasing length of construction times. The delays of these transmission projects do not currently seem to be driving reliability issues.

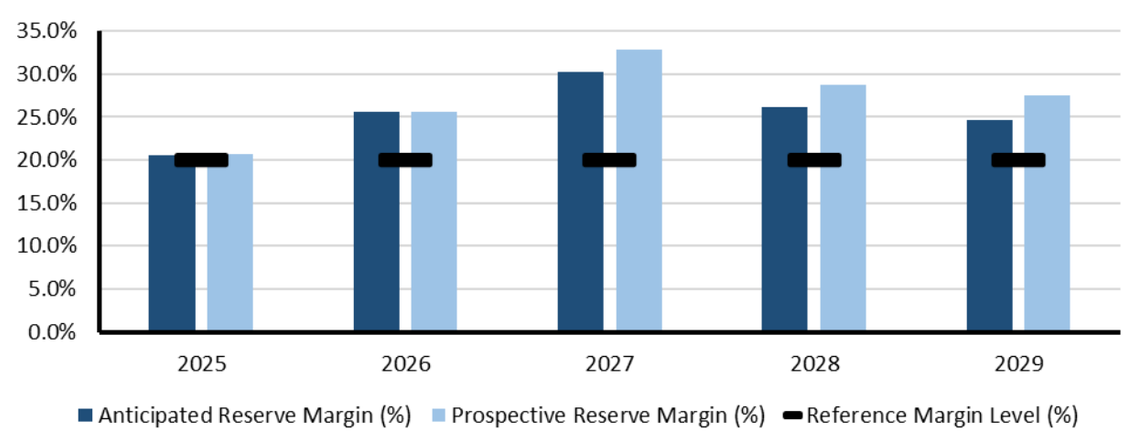


NPCC-Maritimes

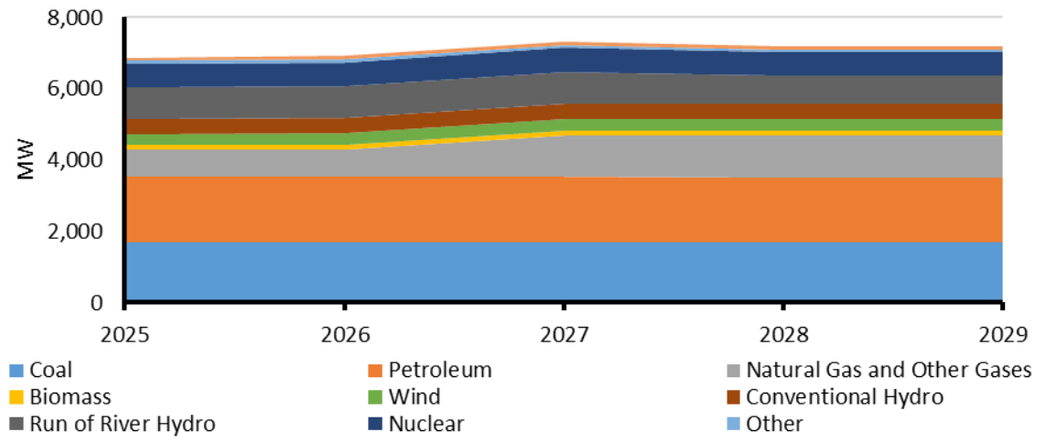
The Maritimes assessment area is a winter peaking NPCC sub-region with a single Reliability Coordinator and two Balancing Authority Areas (New Brunswick and Nova Scotia). It is comprised of the Canadian provinces of New Brunswick (NB), Nova Scotia (NS), and Prince Edward Island (PEI) and the northern portion of Maine (NM), which is radially connected to NB. The area covers 58,000 square miles with a total population of 2 million people.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	6,201	6,056	6,095	6,141	6,216	6,272	6,331	6,398	6,474	6,560
Demand Response	274	293	309	317	317	317	317	317	317	318
Net Internal Demand	5,927	5,763	5,786	5,825	5,899	5,954	6,014	6,081	6,157	6,242
Additions: Tier 1	108	171	579	579	579	579	579	579	579	579
Additions: Tier 2	6	4	447	600	1,398	1,398	1,398	1,398	1,398	1,398
Additions: Tier 3	0	13	80	127	197	255	267	279	291	291
Net Firm Capacity Transfers	289	322	215	145	145	145	145	145	145	145
Existing-Certain and Net Firm Transfers	7,038	7,063	6,959	6,771	6,771	6,771	6,679	6,665	6,665	6,752
Anticipated Reserve Margin (%)	20.6%	25.5%	30.3%	26.2%	24.6%	23.4%	20.7%	19.1%	17.7%	17.4%
Prospective Reserve Margin (%)	20.7%	25.6%	32.8%	28.8%	27.5%	26.3%	23.5%	21.9%	20.4%	20.1%
Reference Margin Level (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Since the *2023 LTRA*, the overall resource outlook has improved with expected new natural-gas-fired generators coming into service in 2027. Winter peak demand forecasts for this assessment area have risen through 2030; however, ARMs are currently projected to remain above the RML of 20% until 2031 when the ARM dips to 19.7%.

NPCC-Maritimes Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**
Coal	1,696	1,696	1,696	1,696	1,696
Coal*	1,696	1,696	1,396	1,248	467
Petroleum	1,831	1,831	1,825	1,819	1,819
Natural Gas	757	757	1,157	1,157	1,157
Biomass	148	148	148	148	148
Solar	5	5	5	5	5
Wind	293	321	329	329	329
Conventional Hydro	412	412	412	412	412
Run of River Hydro	902	902	902	791	791
Nuclear	663	663	671	671	671
Other	77	77	77	77	77
Battery	72	99	99	99	99
Total MW	6,856	6,911	7,321	7,204	7,204
Total MW*	6,856	6,911	7,021	6,756	5,975
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

NPCC-Maritimes Assessment

Planning Reserve Margins

The NPCC-Maritimes assessment area is comprised of NB, NS, PEI, and NM. The RML for the assessment area is 20%; however, this reserve margin is not mandated. The ARM over the study period for the Maritimes area ranges between 17% and 30% during the winter period and between 88% and 93% during the summer period.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

During off-peak hours, the Maritimes area has surplus generation and no constraints with converting the capacity to energy.

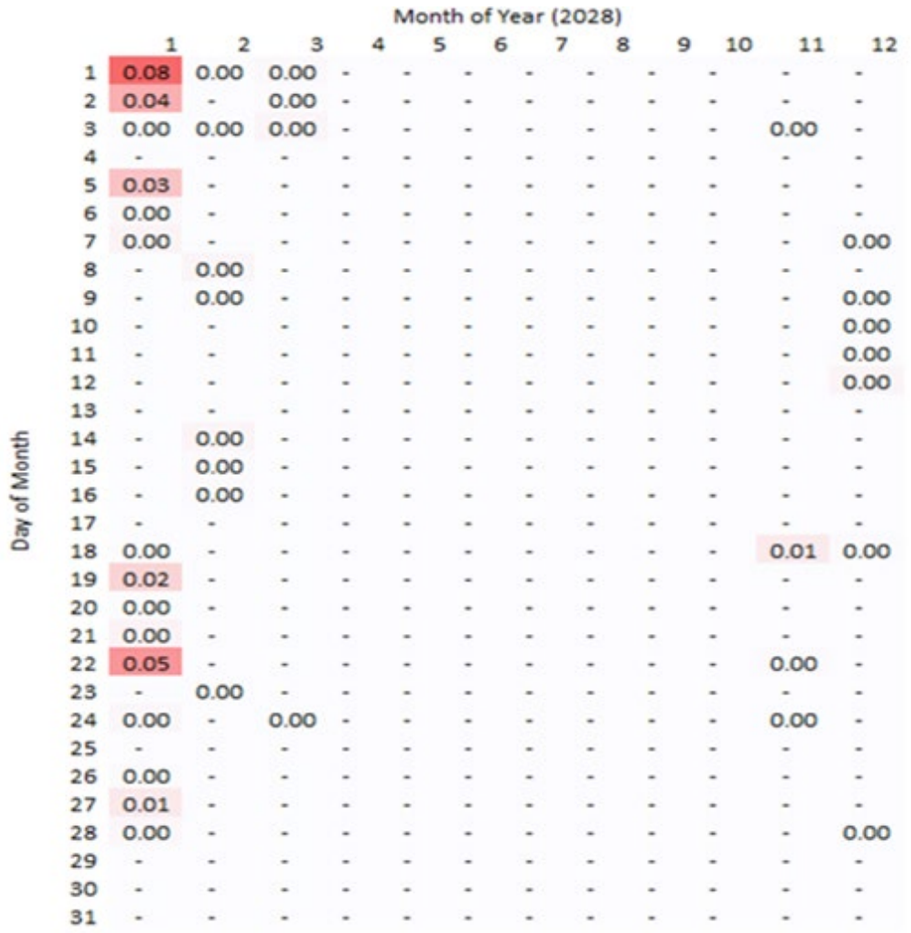
Probabilistic Assessments

Two Balancing Authorities within the Maritimes area are members of NPCC and jointly prepare annual probabilistic assessments that cover three- to five-year forward-looking periods and evaluate the adequacy of the Maritimes' transmission system and resources. In addition, the Maritimes area also supports NERC's annual seasonal ProbAs, which provides an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves. Results of the 2024 ProbA are in the table below.

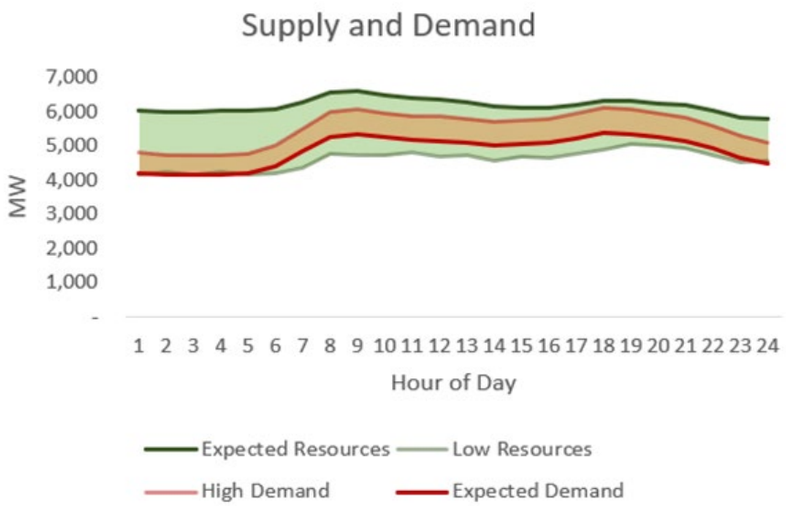
Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	3.87	**5.02**	**0.28**
EUE (PPM)	0.14	**0.17**	**0.01**
LOLH (hours per year)	0.07	**0.09**	**0.02**
Operable On-Peak Margin	22.9%	**17.9%**	**29.0%**

* Provides the 2022 ProbA Results for Comparison

The following table of LOLH for 2028 provides a depiction of risks across the calendar year and highlights the concentration of risk in winter. Most load-loss risk occurs in winter months of December–February, with some additional risk occurring in shoulder months. 2026 has a similar risk distribution.



Hourly demand and resource projections for a typical risk-day in 2026 are shown in the figure below. Expected resource contributions are observed to cover expected demand on the risk day. However, the greatest risk for this assessment area is in the form of lower-than-expected resource contributions. If this were to occur, expected demand for all hours would not be met. This risk would be exaggerated by the addition of a higher-than-expected demand event. Reliance on external assistance may be necessary in these events. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

Demand

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. The peak area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of NB and NS, which are historically highly coincidental. Demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas. The aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of the LTRA assessment period. The area peak loads are expected to increase by 4.2% during summer and by 6.4% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 0.4% in summer and 0.6% in winter. The Maritimes Area annual energy forecasts are expected to increase by a total of 5.9% during the 10-year assessment period for an average growth of 0.6% per year.

Demand-Side Management

Plans to develop up to 100 MW by 2030/2031 of controllable direct load control programs using smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway but no specific annual demand and energy saving targets currently exist. During the 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 20 MW to 169 MW while the annual amounts for winter peak demand reductions rise from 168 MW to 629 MW.[34]

Distributed Energy Resources

The DER installed capacity in NS is approximately 245 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff, and BTM solar.

LTRA wind capacity for NB, NS, and PEI is derated between 18% and 33% using probabilistic methods to calculate equivalent perfect capacities for each sub-area excluding NM, which uses seasonal capacity factors. BTM solar is assumed to have an ELCC of 0% during winter period. The Maritimes area has shown embedded BTM solar PV projections of 149 MW in 2024 rising to 881 MW by 2034. These projects include distributed small-scale solar (mainly rooftop) that fall under the net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar installations in the coming years is a result of initiatives including municipal and provincial incentive programs. There is no capacity contribution from solar generation due to the timing of the area's system peak, which occurs either before sunrise or after sunset in the winter period.

Generation

NB assumes extending 28 MW of diesel-fired generator starting in 2025 and recently upgraded 290 MW of natural-gas-fueled resource completed in 2023. There are 25.2 MW of wind power purchase agreements (PPA) also slated to start in 2025. An anticipated replacement PPA contract, a long-term firm energy contract from a neighboring jurisdiction, and opportunities to buy in day-ahead and real-time markets will be utilized to maintain the overall resource adequacy.

NB Tier 1 resources include 71 MW of wind and 400 MW of combustion turbines. Tier 2 resources include 200 MW of wind resources and Tier 3 includes 400 MW of wind.

In NS, Tier 1 resources include wind projects with a total nameplate capacity of 473 MW phased in from 2024–2027 with an ELCC of 10%, 150 MW battery storage, 4 MW tidal power, 2 MW biomass unit, and a small 0.14 MW solar farm. Tier 2 resources in NS include 250 MW of battery storage (2026–2032), 600 MW of combustion turbines (2027–2033), a 150 MW conversion of a coal-fired unit to natural gas (2028), 450 MW in conversion of coal-fire units to oil (2030), 220 MW of solar generation,

[34] Current and projected energy efficiency effects based on actual and forecasted customer adoption of various DSM programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

and 416 MW of wind generation. Tier 3 resources in NS include natural gas additions (combustion turbines) of 50 MW in 2029 and new wind generation with a nameplate capacity of 850 MW phased in from 2026–2033. These Tier 3 resource additions are anticipated to facilitate the retirement of additional coal-fired generation by 2030. However, these retirements have not been included in the assessment due to their uncertainty.

Small amounts of new solar generation capacity (Tier 1) of up to 21 MW were being installed in PEI in 2024, along with 10 MW of new hybrid energy storage (Tier 1). PEI also has 30 MW of Tier 2 wind, 111 MW Tier 3 wind, and 140 MW of Tier 3 petroleum-based generation and 10 MW of Tier 3 batteries.

NB derates its wind capacity using a calculated year-round equivalent capacity of 22%. NS and PEI derate wind capacity to 18% and 17%, respectively, of nameplate based on year-round calculated equivalent load carrying capabilities for their respective individual sub areas. The peak capacity contribution of grid-based solar is estimated at zero since the Maritimes area peak occurs in the winter either before sunrise or after sunset.

Energy Storage

NS Power includes a 150 MW (4-hour duration) nameplate standalone battery resource as a Tier 1 resource and a 250 MW (4-hour duration) nameplate capacity standalone battery resource added as a Tier 2 resource phased in from 2026 through 2032. This grid-scale project will support the integration of new renewable generation, provide energy arbitrage and resiliency services, and provide firm capacity and fuel savings.

PEI includes a 10 MW nameplate capacity hybrid energy storage as a Tier 1 resource starting summer of 2024 and another 10 MW nameplate capacity energy storage system as a Tier 3 resource. This project will provide a storage option for the output from the 10 MW solar facility that is planned to come online during the same time frame. This project will provide fuel savings and may assist in providing additional reliability if a generation outage occurs.

NB Power has not included any energy storage resources in the *2024 LTRA* submission; however, the value of energy storage options is expected to increase as the technology improves and as NB's smart grid network develops. NB Power issued a request for expressions of interest for new renewable generation sources including 200 MW of wind, 15 MW of solar, 5 MW of tidal, and 50 MW of 4-hour duration battery storage in February 2023. Under this program, NB Power expects uptake in new energy storage projects in the coming years. Internal pilot projects and studies are underway to understand the economics, application, and performance of battery storage resources. Ongoing internal analyses are conducted by NB Power to determine the cost and benefit associated with battery storage options and dispatching these resources to reduce/shift peaks and/or balance intermittent resources, such as wind, to provide additional flexibility to the system.

Capacity Transfers

ProbA studies show that the Maritimes area is not reliant on inter-area capacity transfers to meet NPCC resource adequacy criteria.

Transmission

NS has multiple new transmission line projects compared to the *2023 LTRA*; most being shorter runs to enable the connection of renewable resources, with one major project of 165 miles designed to improve the reliability of the existing tie between NS and NB.

Reliability Issues

The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (derated), dual fuel oil/gas, tie benefits, and biomass with no single one type feeding more than about 27% of the total capacity in the area. The Maritimes area does not anticipate fuel disruptions that pose significant challenges for resources during this assessment period.



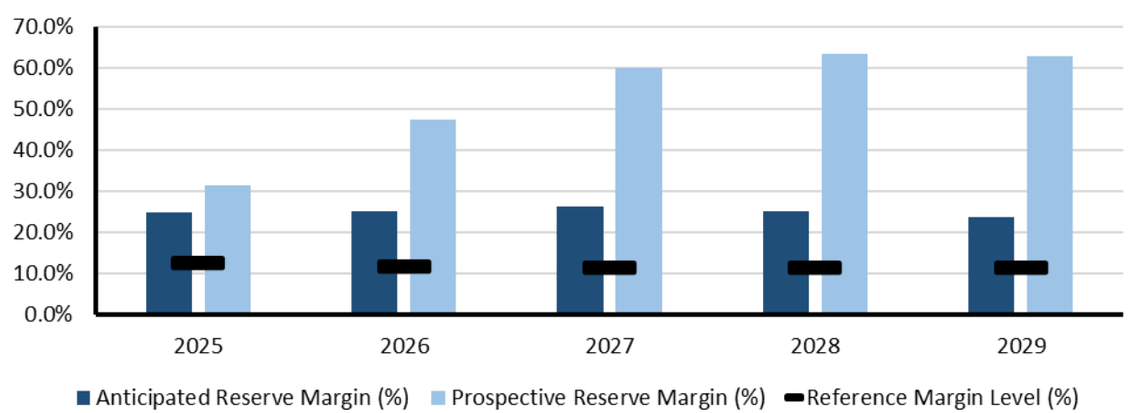
NPCC-New England

NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO New England Inc. (ISO-NE). ISO-NE is a regional transmission organization responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS. Note: Northern Maine is not directly connected to the transmission system administered by ISO-NE.

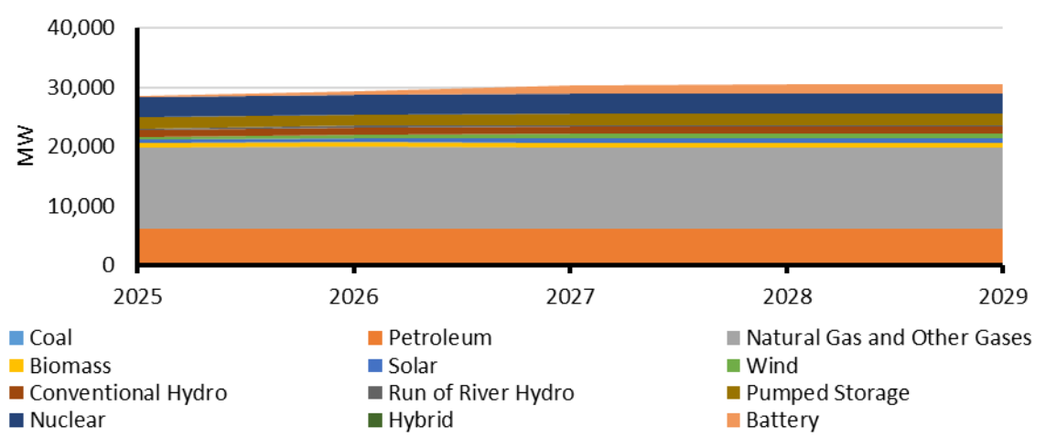
The New England BPS serves approximately 15.1 million customers over 68,000 square miles.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	24,579	24,702	24,845	25,076	25,364	25,706	26,100	26,547	27,052	27,567
Demand Response	566	588	544	544	544	544	544	544	544	544
Net Internal Demand	24,013	24,114	24,301	24,532	24,820	25,162	25,556	26,003	26,508	27,023
Additions: Tier 1	660	1,492	2,374	2,748	2,748	2,748	2,748	3,168	3,168	3,168
Additions: Tier 2	337	3,089	5,911	7,084	7,425	7,766	7,766	7,766	7,766	7,766
Additions: Tier 3	1,404	1,765	5,106	7,906	9,221	9,355	9,721	10,432	10,432	10,432
Net Firm Capacity Transfers	1,248	567	465	84	84	84	84	84	0	0
Existing-Certain and Net Firm Transfers	29,354	28,658	28,327	27,946	27,946	27,946	27,946	27,946	27,862	27,862
Anticipated Reserve Margin (%)	25.0%	25.0%	26.3%	25.1%	23.7%	22.0%	20.1%	19.7%	17.1%	14.8%
Prospective Reserve Margin (%)	31.4%	47.3%	60.1%	63.3%	62.8%	62.0%	59.5%	58.3%	55.0%	52.0%
Reference Margin Level (%)	12.7%	11.8%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- New England is forecast to have sufficient ARMs to meet consumer demand for electric energy for the first five years (2025–2029) of the assessment period and not require any Tier 2 resources.
- ISO-NE is addressing the issues brought on by grid transformation through several planning, operational, and market measures. A significant project is the redesign of the capacity market from a forward, annual auction to a prompt, seasonal auction with resource accreditation. The Capacity Auction Reforms (CAR) project began in Q2 2024 and is expected to be in place for the 19th Capacity Commitment Period (CCP 19) beginning on June 1, 2028. Additionally, New England has made tariff modifications to its Longer-Term Transmission Planning process to facilitate the New England states' achievement of their policy-based goals by enabling the development of transmission infrastructure. ISO-NE is also working with regional stakeholders to develop a regional energy shortfall threshold (REST) that defines the region's tolerance for energy shortfalls during low-probability extreme weather conditions.

NPCC-New England Projected Generating Capacity by Energy Source in Megawatts (MW)[35]					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	541	541	541	541	541
Coal*	445	445	445	7	7
Petroleum	5,703	5,703	5,687	5,687	5,687
Natural Gas	13,651	13,724	13,708	13,708	13,708
Biomass	780	780	780	780	780
Solar	533	663	663	663	663
Wind	391	594	819	819	819
Conventional Hydro	1,209	1,209	1,209	1,209	1,209
Run of River Hydro	289	289	289	289	289
Pumped Storage	1,860	1,860	1,860	1,860	1,860
Nuclear	3,331	3,331	3,331	3,331	3,331
Hybrid	34	35	35	35	35
Other	74	74	74	74	74
Battery	159	584	1,242	1,616	1,616
Total MW	28,553	29,385	30,237	30,611	30,611
Total MW*	28,458	29,290	30,141	30,077	30,077
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to ISO-NE are removed from the resource projection where marked.					

[35] MW totals reflect Existing and Tier 1 generation. Generator retirements in this timeframe would be captured if a resource submits a retirement request through the ISO-NE capacity market.

NPCC-New England Assessment

Planning Reserve Margins

ISO-NE's installed capacity requirement (ICR) is based on the capacity needed to meet the ISO-NE and NPCC resource adequacy reliability criterion of an LOLE of 0.1 day/year. The ICR varies from year to year depending on projected system conditions. The ICR is calculated on an annual basis, in advance of the capacity auctions for each Capacity Commitment Period. The latest ICR calculations result in an annual RML of 12.70% in 2025, 11.82% in 2026, and 11.33% in 2027, expressed in terms of the annual 50/50 peak demand forecast published in the *2024 Capacity, Energy, Loads, and Transmission (CELT) Report*. For the years 2028 through 2034, which are beyond the current forward capacity market timeframe, ISO-NE continued to use the last available RML value of 11.33%. The ISO-NE RML is relatively low compared to other regions due to the impact of reflecting external assistance from neighboring control areas and the continued increase in BTM solar facilities.

Non-Peak Hour Risk, Energy Assurance, and Probabilistic-Based Assessments

ISO-NE routinely prepares 21-day energy forecasts. These forecasts incorporate weather, transmission topology, resource capability and availability, fuel inventories and constraints, and projected imports/exports. If the forecasted regional supply/demand balance is negative, projected energy deficiencies can trigger energy alerts or energy emergencies that are then disseminated to market participants and federal and state regulators. This early notification of potential energy shortfalls is expected to inform market participants such that actions can be taken to increase the expected availability of generating resources as needed.

ISO-NE recently completed work with the Electric Power Research Institute (EPRI) to develop the Probabilistic Energy Adequacy Tool (PEAT) framework. This tool is a framework that has three major steps (weather modeling, risk screening/scenario generation, and 21-day energy assessment), which were subsequently applied to assess the summers and winters of 2027 and 2032.

Probabilistic Assessments

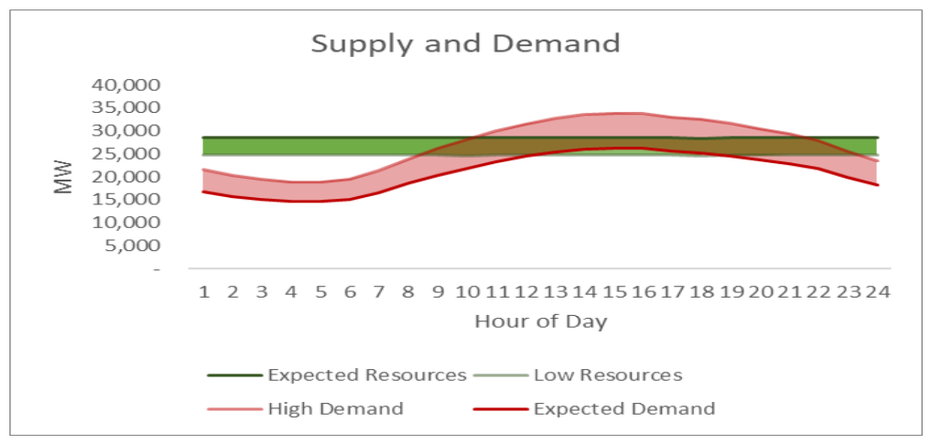
ISO-NE conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and to comply with NPCC/NERC reliability requirements. In the transmission assessment domain, revisions to ISO-NE planning processes reflect the changing resource characteristics, probabilistic study assumptions, and changes to national and regional criteria. Coordinated planning activities with neighboring systems will continue and help support the New England states' policy objectives of providing access to a greater diversity of clean resources to meet environmental compliance obligations. Results from the 2024 ProbA, shown in the table below, reveal a slight increase in load-loss and unserved energy risk from the 2022 analysis, but values remain small. ISO-NE is considered to have sufficient resources for the planning horizon to meet NPCC resource adequacy criteria.

Base Case Summary 2024 ProbA of Results			
	2026*	2026	2028
EUE (MWh)	0.551	**10.69**	**7.40**
EUE (PPM)	0.004	**0.09**	**0.06**
LOLH (hours per year)	0.002	**0.07**	**0.03**
Operable On-Peak Margin	27.8%	**12.4%**	**13.7%**

* Provides the 2022 ProbA Results for Comparison

NPCC's ProbA results indicate that the risk of unserved energy in New England is concentrated in summer months (June–August).

Hourly demand and resource projections for a typical summer risk day in 2026 are shown in the figure below. Although expected resource contributions meet expected demand, there is risk that above-normal peak demand could exceed resources. Demand could be 25–30% higher than expected, which could cause strain on the system from the hours beginning 10:00 a.m. through 10:00 p.m. Also, below-normal resource performance from unexpected generator outages or low solar output could also cause supply shortfalls. If resource contributions are less than expected, strain on the system could be seen from the hour beginning 12:00 p.m. through 7:00 p.m. on a typical peak day. Reliance on external assistance may be necessary in these extreme conditions. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

Fuel availability during extreme winter conditions is a persistent reliability concern in New England that is not modeled in detail in the ProbA. Potential natural gas transportation constraints can affect supply to generators during extreme cold temperatures, when natural gas demand for space heating is also peaking. Most natural-gas-fired generators in the area do not have firm natural gas transportation service and can be subject to supply curtailment during peak conditions. Many natural-gas-fired generators in New England can also operate with stored oil, providing for assured electricity supply in extreme winter conditions while oil stores are procured and maintained. Scenarios of extended and extreme cold weather that affect the availability of natural gas and oil replenishments present a reliability risk and were not modeled in the 2024 ProbA.

Demand

Over the 10-year LTRA planning horizon, the forecast net internal summer peak demand increases by 2,988 MW from 24,579 MW in 2025 to 27,567 MW in 2034 (roughly 2% decrease from the 2023 forecast in the later years). The corresponding net internal winter peak demand increases by 7,342 MW from 20,639 MW in 2025–2026 to 27,981 MW in 2034–2035 (roughly a 2.5% decrease from the 2023 forecast). Net energy for load is forecast to grow by 24,701 GWh from 119,285 GWh in 2025 to 143,986 GWh in 2034 (roughly 10% decrease from the 2023 forecast). The changes from the 2023 forecast were in part due to continued enhancements of the heating and transportation electrification forecasts.

The higher winter peak growth rate due to anticipated electrification results in significant convergence with summer peak projections by the end of the 10-year period, such that New England's transition to a winter-peaking system is currently anticipated by the mid-2030s. It is also expected that the timing of the peaks will likely occur in the morning by this time, with heating electrification in particular inducing a greater tendency for morning peaks due to electrified residential and commercial heating.

Demand-Side Management

For the summer of 2025, ISO-NE forecasts 566 MW of controllable and dispatchable demand-side management (DSM) resources, and that amount is projected to decrease by 22 MW to 544 MW by 2034. For the summer of 2025, ISO-NE forecasts 1,873 MW of passive DSM resources (EE and conservation). Demand-side resources are projected to peak in 2030 at 2,117 MW and then begin to decrease to 1,978 MW by 2034. This decrease in the later years is due to expiring EE measures outpacing new passive DSM additions.

Distributed Energy Resources

For summer months, the BTM PV forecast is incorporated as estimated reductions to the ISO-NE gross demand forecast. In 2025, New England forecasts 1,141 MW of peak load reduction (4,533 MW nameplate) of BTM PV. BTM PV is forecast to grow to 1,299 MW of peak load reduction (8,217 MW nameplate) by 2034. The BTM PV peak load reduction values are calculated as a percentage of ac nameplate. The percentages include the effect of diminishing PV production at the time of the system peak as increasing PV penetrations shift the timing of peaks later in the day. The BTM peak load reduction decreases from 25.2% of nameplate in 2025 to 15.8% in 2034.

ISO-NE recently adopted a new planning procedure (PP12) to formalize and standardize data collection for DERs. Under this procedure, distribution providers would be responsible for providing installation-level data on DERs connected to their system. Additionally, transmission providers would be responsible for providing basic data to translate feeder IDs into substation names and other useful identifying information. Among the other benefits that this procedure will lead to is "*proper accounting for the location, size, and type of DER which will lead to more accurate study outcomes.*"

Generation

The largest change that will impact New England's generation fleet is ISO-NE's CARs.

Specifically, to better ensure power system reliability and cost efficiency as New England's resource mix evolves, ISO-NE is proposing a CAR that would transition the capacity market from a forward/annual market to a prompt/seasonal market with accreditation reforms. This initiative has three primary components that would be in place for the Capacity Commitment Period (CCP) scheduled to start on June 1, 2028.

- Prompt auction: Instead of taking place three years in advance, the capacity auction would take place shortly before the CCP, reflecting more accurate information about projected electricity supply and demand.
- Seasonal CCP: The CCP changes from annual to sub-annual (seasonal) commitment periods to better address the distinct reliability challenges of winter and summer, as well as variations in resource performance from season to season.
- Accreditation reforms: Work began in 2022 via the former "Resource Capacity Accreditation in the Forward Capacity Market" project to identify and implement methodologies that will more accurately reflect resource contributions to resource adequacy in the capacity market. It is critical to the reliable and efficient clean-energy transition that the accreditation methodologies are updated to reflect resources' capabilities and how those capabilities contribute to resource adequacy. This work continues through CAR in the context of the proposed market constructs.

Energy Storage

New England currently has a total of 1,899 MW of energy storage capacity. This number includes about 39 MW of battery storage (BESS) and hybrid solar/battery storage. The largest energy storage resource(s) in New England are three pumped-storage hydro-electric facilities that can supply a combined 1,860 MW of quick-start 10-minute operating reserve capability, and with full reservoirs, and can deliver over 11,800 MWh of energy to the BPS.

Over the next five years (2025–2029), the nameplate capacity of energy storage devices (BESS, integrated-hybrid, and co-located-hybrid) are projected to increase significantly (Tier #1 [1,607 MW], Tier #2 [5,047 MW], and Tier #3 [4,955 MW]). No new pumped-storage facilities are planned for the region. Over the next 10 years, those total Tier 1–3 capacities do not increase from the five-year projection. All the above capacity totals reflect summer seasonal claimed capability ratings.

Capacity Transfers

New England is interconnected with the three BAs of Québec, the Maritimes, and New York. ISO-NE considers the tie benefits associated with these BAs within its capacity market methodology to reduce the installed capacity requirement to meet the regional resource adequacy criterion. Assumed assistance from tie benefits ranges from 1,830 MW in 2025 to 2,115 MW in 2027. Aside from such assistance, ISO-NE's firm capacity imports are projected to range from a maximum of 1,248 MW in the summer of 2025 down to 465 MW in the summer of 2027. There is one long-term firm import contract of 84 MW that extends through the summers of 2028 through 2032. There are currently no firm imports projected for the summers of 2033 and 2034. In addition, there are no firm exports identified over the 10-year assessment.

Transmission

Transmission expansion in New England has improved the overall level of reliability and resiliency, reduced air emissions, and lowered wholesale market costs by nearly eliminating congestion. Generator retirements, off-peak system needs, the growth of DERs and VERs using IBRs, and changes to mandatory planning criteria promulgated by NERC, NPCC, and regional stakeholders have driven the need for longer-term transmission assessments.

The future reliable and economic performance of the BPS is expected to be maintained as a result of approximately $1.5 billion of planned transmission upgrades over the next 10 years. Generator retirements, the integration of many DERs and VERs, the use of IBR technologies, and issues rising from minimum load assessments and high-voltage conditions are changing the needs for reliability-based transmission upgrades. Interregional import capability will also increase with the completion of the 1,200 MW HVdc New England Clean Energy Connect (NECEC) tie line between Québec and Maine, scheduled to be in service by the beginning of 2026.

In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy and serve increased load as transportation and heating are electrified. Transmission assessments and resultant plans are being developed throughout the region to meet these future system needs.

Reliability Issues

New England's BPS is transitioning to a system with unprecedented demand growth, due to electrification of heating and transportation, and a growing number of renewables, clean energy resources, VERs, and DERs. ISO-NE is engaged in the implementation of revised interconnection standards for VERs and DERs that will ensure overall BPS reliability and facilitate the economic development of IBRs.

ISO-NE has observed some delays in projected in service dates for system upgrades due to supply chain issues. In these cases, ISO-NE develops operating plans to work around any issues caused by these delays. Additionally, the New England Transmission Owners have indicated that supply chain issues are causing a notable increase in project costs.

New England has already experienced constraints on electric energy production due to constraints on fuel infrastructure that have an impact on the power sector during winter. In response, ISO-NE has been a key player at the national level in promoting BPS reliability through sharing of lessons learned, best practices, and, more recently, through the performance of more detailed and in-depth BPS energy assessments. Additionally, to address winter energy security challenges, ISO-NE and regional stakeholders developed and put in place a two-year program to compensate certain resources that provide energy security during the winters of 2023–2024 and 2024–2025 (from December to February). ISO-NE's Inventoried Energy Program (IEP) is a voluntary program designed to provide incremental, winter-period compensation for participants that maintain inventoried energy for their assets during extreme cold periods when energy security is most stressed.

The just-in-time delivery of a generator's fuel supply, whether natural gas, wind, or solar, is creating the need for the electric sector to quickly develop ways to retain access to flexible, stored energy—either through long-term energy storage solutions that can capture and store renewable power or through the use of dispatchable resources.

ISO-NE is actively working on numerous major projects to prepare for the clean energy transition and ensure continued reliability. The following is a short list of major projects in which ISO-NE has engaged:

- **CAR Project**
- **Operational Impacts of Extreme Weather Events**
- **Regional Energy Shortfall Threshold**
- **Day-Ahead Ancillary Services Initiative**
- **Economic Planning for the Clean Energy Transition (EPCET)**
- **Extended-Term Transmission Planning Tariff Changes**
- **Longer-Term Transmission Studies**
- **Storage As Transmission Only Asset (SATOA)**
- **FERC Order No. 1920 Project**
- **FERC Order No. 2023 & 2023-A Project**
- **FERC Order No. 2222 Project**
- **FERC Order No. 881 Project**

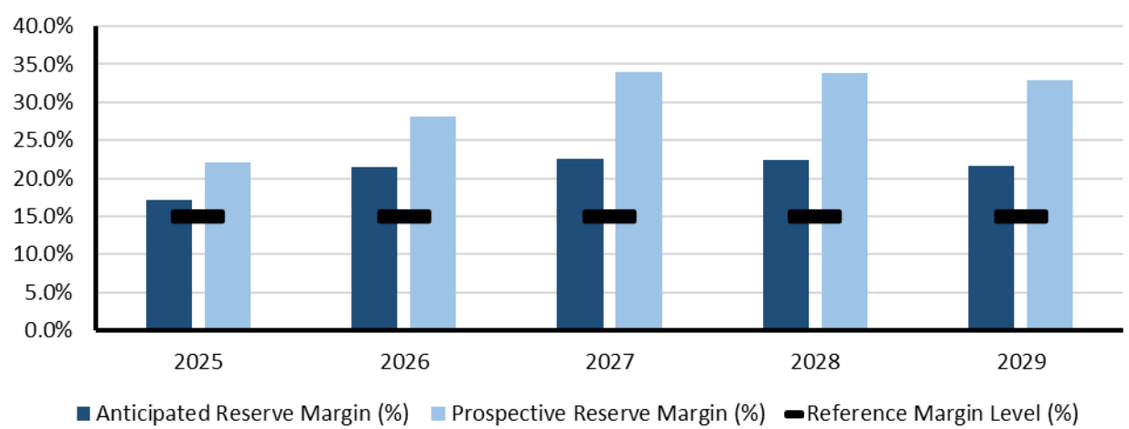


NPCC-New York

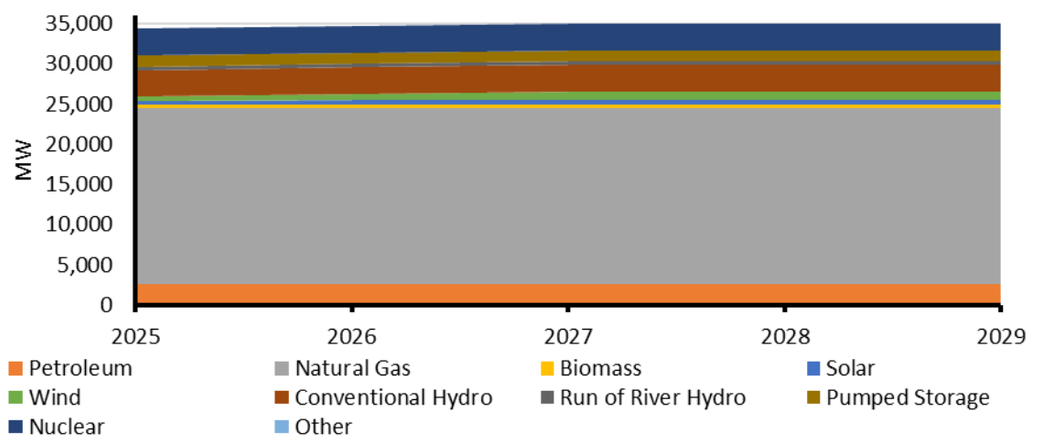
NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only Balancing Authority within the state of New York. The BPS encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this LTRA, the established RML is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). The NYSRC approved the 2025–2026 IRM at 24.4%.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	31,650	31,900	32,110	32,130	32,340	32,580	32,880	33,320	33,830	34,210
Demand Response	897	897	897	897	897	897	897	897	897	897
Net Internal Demand	30,754	31,004	31,214	31,234	31,444	31,684	31,984	32,424	32,934	33,314
Additions: Tier 1	495	858	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144
Additions: Tier 2	1,558	2,090	3,572	3,572	3,572	3,572	3,572	3,572	3,572	3,572
Additions: Tier 3	1,381	4,384	6,384	7,928	8,383	8,383	8,383	8,383	8,383	8,383
Net Firm Capacity Transfers	1,600	2,880	3,186	3,186	3,186	3,186	3,186	3,186	3,186	3,186
Existing-Certain and Net Firm Transfers	35,511	36,790	37,096	37,097	37,097	37,097	36,687	36,687	36,687	36,687
Anticipated Reserve Margin (%)	17.1%	21.4%	22.5%	22.4%	21.6%	20.7%	18.3%	16.7%	14.9%	13.6%
Prospective Reserve Margin (%)	22.1%	28.2%	34.0%	33.9%	33.0%	32.0%	29.5%	27.7%	25.7%	24.3%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Public policies, such as New York state's 2019 Climate Leadership and Community Protection Act (CLCPA), are driving rapid changes in New York's electric system, impacting how electricity is produced, transmitted, and consumed. The transition to a cleaner grid in New York is leading to an electric system that will be increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation.
- Recent assessments reveal that reliability margins are shrinking. Electrification programs are increasing the demand for electricity and placing New York on a trajectory to be a winter-peaking system in the future. Largely in response to public policies, fossil fuel generators are retiring at a faster pace than new renewable supply is entering service. The potential for delays in construction of new supply and transmission, higher than forecasted demand, and extreme weather could threaten reliability and resilience of the New York grid.
- NYISO's reliability studies identified actionable reliability needs starting 2025 in New York City. The reliability need is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by state legislation and regulations promulgated by the New York State Department of Environmental Conversation, commonly known as the Peaker Rule,[36] to limit emissions. Following a solicitation for proposed solutions to the reliability need, NYISO retained several plants in New York City that would have otherwise been deactivated to comply with the Peaker Rule. NYISO's 2024 Reliability Needs Assessment (RNA), targeting completion in the fourth quarter of 2024, identifies transmission security violations of reliability criteria primarily driven by a combination of forecasted increases in peak demand, limited additional supply, and the assumed retirement of generation in New York City in response to state law and regulations.
- Driven by public polices, new supply, large loads, and transmission projects are seeking to interconnect to the grid at record levels. NYISO's interconnection process balances developer needs with grid reliability. Efforts are underway to make this process more efficient while protecting grid reliability. New transmission is being built, but more investment is necessary to support the delivery of offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest. Planning for new transmission to support offshore wind is underway in NYISO's Public Policy Transmission Planning Process.
- To achieve the mandates of the CLCPA, new dispatchable emission-free resources (DEFR) with the necessary reliability services will be needed to replace the capabilities and attributes of today's generation. These types of resources, which can achieve the necessary attributes by a combination of solutions, must be significant in capacity and have attributes similar to traditional generation plants, such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, provide ERSs, and adapt to meet rapid, steep ramping needs. Such new emission-free supply is not yet available on a commercial scale.
- New wholesale electricity market rules are supporting the grid in transition. These markets are critical for a reliable transition. Wholesale electricity markets are open to significant investment in wind, solar, and battery storage as well as distributed energy resources. Demand management programs are also under development as a measure to facilitate achievement of CLCPA targets. By lowering the peak load and avoiding system buildout to serve the highest demand hour, fewer DEFRs will be needed and fewer fossil fuel-fired plants will be needed to meet lower peaks during the transition.

[36] Subpart 227-3 of Title 6 of the New York Codes, Rules an3,323d Regulations.

NPCC-New York Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Petroleum	2,631	2,631	2,631	2,631	2,631
Petroleum*	2,628	2,628	2,628	2,628	2,628
Natural Gas	21,907	21,907	21,907	21,907	21,907
Biomass	334	334	334	334	334
Solar	545	586	586	586	586
Wind	461	785	1,070	1,070	1,070
Conventional Hydro	3,323	3,323	3,323	3,323	3,323
Run of River Hydro	413	413	413	413	413
Pumped Storage	1,410	1,410	1,410	1,410	1,410
Nuclear	3,330	3,330	3,330	3,330	3,330
Battery	50	50	50	50	50
Total MW	34,405	34,769	35,054	35,054	35,054
Total MW*	34,401	34,765	35,051	35,051	35,051
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to NYISO are removed from the resource projection where marked.					

NPCC-New York Assessment

Planning Reserve Margins

The LTRA anticipated and prospective margins are above 15% with the exception of year 9 (2033) and year 10 (2034). However, the system margins are narrowing throughout the assessment period. Wind, grid-connected solar, and run-of-river totals were derated for the LTRA calculation. Under its reliability planning processes, NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of no greater than 0.1 event-days/year probability of unplanned load loss. NYISO's 2024 Reliability Needs Assessment, which is underway and targets completion in Q4 2024, will likely identify reliability criteria violations.

NYISO also provides support to the NYSRC in conducting an annual IRM study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the NPCC and NYSRC resource adequacy criterion of "1 day in 10 years." The current IRM for the 2024–2025 capability year is 22% of the forecasted NYCA peak load. All values in the IRM calculation are based upon full installed capacity values of resources. The IRM has varied historically from 15% to 22%. Additionally, the NYISO performs an annual study to identify the locational minimum installed capacity requirements (LCR) for the upcoming capability year.

Energy Assessment, Including Non-Peak Hour Risk

New York State's CLCPA mandates to decarbonize span over all major industries and are a main driver for the electric system changes. NYISO staff in system operations, planning, and markets will continue to assess the system changes to prepare for the grid's transformation.

With high penetration of renewable intermittent resources, the system will need dispatchable emission-free resources (DEFR) and long-duration resources to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. Additionally, although new transmission is being built, more investment is necessary to support the delivery of future offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest.

NYISO performs long-range assessments (10-year and beyond planning horizon), and certain energy aspects are accounted for in the hourly modeling and simulations performed under the resource adequacy studies through NYISO's reliability planning processes along with the production cost simulations performed under its System and Resource Outlook.

NYISO performs and supports energy assessments, including a fuel and energy security study, a study assessing potential impacts related to climate change, and weekly analysis of fuel and energy security based on load profiles and fuel inventories reported through NYISO's Generator and Fuel Emissions Reporting (GFER) data portal. These assessments are based on data and information provided by resources on an annual, weekly, and as-needed basis considering system operating conditions. These assessments have the capability to analyze the impact of changes in stored fuel inventory, resource outages, fuel supply disruptions, transmission constraints, and other relevant conditions that may adversely impact fuel and energy security. Additionally, the New York City and Long Island areas have a loss of gas supply dual-fuel requirement and certain combined cycle gas units participate in a "Minimum Oil Burn" program. While oil accounts for a relatively small percentage of the total energy production in New York, it is often called during critical periods, such as when severe cold weather limits access to natural gas.

Probabilistic Assessments (NERC ProbA and Other Studies)

NYISO performs probabilistic assessments using GE's Multi-Area Reliability Simulation (MARS) as part of its reliability planning processes as well as to determine annual IRM LCRs. NYISO also pursued capacity accreditation market rules to more accurately reflect capacity market suppliers' contributions to resource adequacy. These new market rules align compensation for capacity suppliers with an individual resource's expected reliability benefit to consumers and uses the probabilistic models from the LCR process to define capacity accreditation factors (CAF) for various capacity accreditation resource classes. The groundbreaking proposal was accepted by FERC in May 2022. The CAFs will reflect the marginal reliability contribution of the ICAP Suppliers within each Capacity Accreditation Resource Class toward meeting NYSRC resource adequacy requirements for the upcoming capability year, starting with the capability year that began in May 2024.

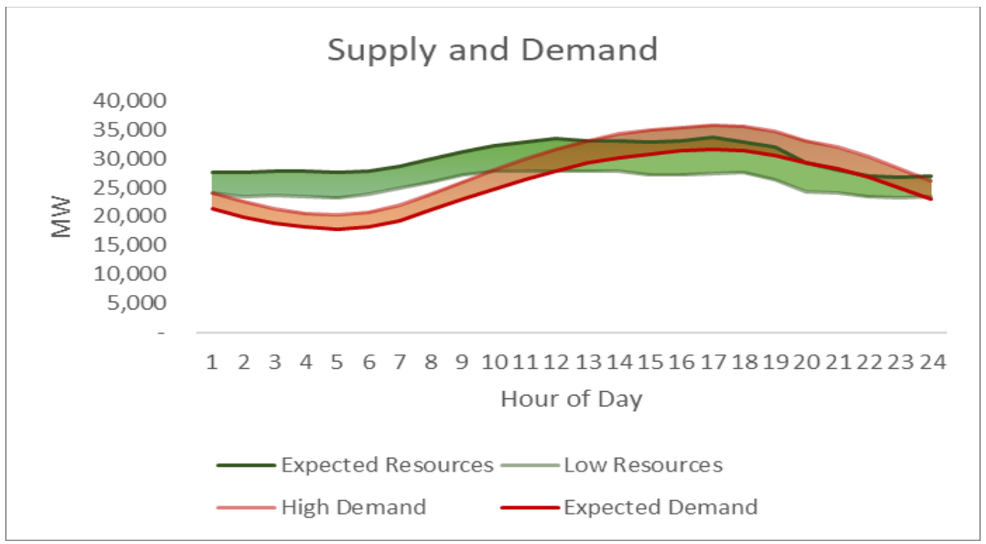
Additionally, NPCC provides results into NERC's ProbA process under the LTRA. The results from the ProbA performed in 2024 by NPCC are shown below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.06	1.91	1.30
EUE (PPM)	0.00	0.01	0.01
LOLH (hours per year)	0.00	0.01	0.01
Operable On-Peak Margin	16.7%	14.0%	15.0%

* Provides the 2022 ProbA Results for Comparison

Most load-loss and unserved energy risk is in the summer months of late June through August.

Hourly demand and resource projections for a typical summer risk day in 2026 are shown in the figure below. Although expected resource contribution is enough to meet expected demand, there is risk that above-normal peak demand could exceed resources. Demand could be 10–13% higher than expected, which could cause strain on the system from the hours beginning 2:00 p.m. through 11:00 p.m. Also, below-normal resource performance from unexpected generator outages or low-solar output could also cause supply shortfalls. If resource contributions are less than expected, strain on the system could be seen from hour beginning 12:00 p.m. through 12:00 a.m. on a typical peak day. Reliance on external assistance may be necessary in these events. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

NPCC's Directory 1 defines a compliance obligation for the NYISO, as a Resource Planner and Planning Coordinator, to perform a resource adequacy study evaluating a five-year planning horizon. NYISO delivers a report every year under this study process to verify the system against the 1-day-in-10-years LOLE criterion, which is usually based on NYISO's latest available reliability assessment results and assumptions. NYSRC Reliability Rules have recently included a requirement defining NYISO's obligation to deliver a Long-Term Resource Adequacy Assessment Report every year during which the NYISO publishes a Reliability Needs Assessment (RNA) and an annual update in the intervening year between RNAs.

Demand

NYISO employs a multi-stage process to develop load forecasts for each of the 11 zones within the New York Control Area (NYCA). The impacts of net electricity consumption of energy storage resources due to charging and discharging are added to the energy forecasts, while the peak-reducing impacts of BTM energy storage resources are deducted from the peak forecasts.

Currently, the NYCA summer peak typically occurs in late afternoon. The NYCA summer peak is projected to shift into the evening as additional BTM solar is added to the system and as EV charging impacts increase during the evening hours. Because the hour of the summer peak shifts into the evening over the course of the forecast horizon, BTM solar generation becomes less coincident with the NYCA peak hour, and BTM solar coincident peak reductions are forecasted to decrease in later years. The forecast of solar PV-related reductions to the winter peak is zero because the system typically peaks after sunset.

Trended weather conditions from the Climate Impact Study Phase I report are included in NYISO's end-use models and are reflected in the baseline, policy scenario, and percentile forecasts. NYISO develops 90th and 99th percentile forecasts to account for the impacts of extreme weather on seasonal peak demand and calculates 10th percentile forecasts to represent milder seasonal peak conditions.

The 10-year annual average energy (+1.7%) and summer peak demand (+0.8%) growth rates are higher than last year's forecast. Increases in growth rates relative to the prior forecast are primarily attributed to the significant impacts of interconnecting large load projects. Baseline energy and coincident peak demand increase significantly throughout the 30-year forecast period, driven largely by large load project growth in the early forecast years and electrification of space heating, non-weather sensitive appliances, and EV charging in the outer forecast years. New York is projected to become winter-peaking in future decades due to space heating electrification and EV penetration. To account for forecast uncertainty during winter due to electrification and large loads, NYISO implemented a winter dynamic load forecast uncertainty in the resource adequacy models for its 2024 RNA.

Demand-Side Management

NYISO is working on developing market concepts to encourage the participation of flexible load, which will become increasingly important as the levels of weather-dependent intermittent resources on New York's grid increase in response to the state's climate and clean energy policies. Many of New

York's utilities are piloting several load management programs (e.g., smart EV charging, home-thermostat use, and integration of BTM storage for local peak demand modulation). As part of NYISO's annual long-term forecasting process, the impacts of these programs are discussed and significant impacts on demand are included in the load forecast.

DR participation for the summer capability period has increased slightly from 1,234 MW to 1,281 MW since the *2023 LTRA*. There are currently 425 MW of DR participating in ancillary services programs and providing either 10-minute spinning reserves or 30-minute non-synchronous reserves.

Distributed Energy Resources

NYISO has implemented in 2024 a plan to integrate DERs, including DR resources, into the markets it administers. The DER Participation Model project aims to enhance participation of DERs in the competitive wholesale markets. These measures closely align the bidding and performance measurements for DERs with the rules for generators. The measures establish a state-of-the-art model that is largely consistent with the market design envisioned by FERC in its Order 2222. This project, which began in 2017, provides a single participation model for DER DR resources to provide energy, ancillary services, and installed capacity through an aggregation. The market rules for the DER and aggregation participation model were accepted by FERC in January 2020. NYISO filed additional proposed tariff revisions with FERC in June 2023 to clarify and enhance these market rules. NYISO deployed its DER participation model in 2024.

Generation

The pace of renewable project development and existing generation retirement is unprecedented and driving a need to increase the pace of transmission expansion, clean dispatchable generation, and demand management programs development. In general, resource and transmission expansion take many years from development to deployment. Coordination of project additions and retirements is essential to maintaining reliability and achieving policy. Significant new resource development will be required to achieve energy targets under the CLCPA. The total installed generation capacity to meet policy objectives within New York is projected to range between 111 GW and 124 GW by 2040. At least 95 GW of this capacity will consist of new generation projects and/or modifications to existing plants. Even with these additions, New York still may not be sufficient to maintain the reliable electricity supply. The sheer scale of resources needed to satisfy system reliability and policy requirements within the next 20 years is unparalleled.

Currently, NYISO's interconnection process contains a significant number of proposed projects in various stages of development with only a fraction in more advanced stages included in the reliability planning models. However, the grid will evolve to achieve the policy mandates, and those changes will affect the nature and amount of resources.

For the 2024 RNA, gas availability is derated during winter to further account for cold weather risks.

To achieve the CLCPA mandate of an emission-free grid by 2040, DEFRs must be developed and deployed throughout New York. DEFRs that provide sustained on-demand power and system stability will be essential to meeting policy objectives while maintaining a reliable electric grid. While essential to the grid of the future, such DEFR technologies are not commercially available today.

ERSs usually provided to the system by synchronous fossil generation will continue to be necessary. New technology is being developed to allow for a reliable transition to a clean grid. Grid-forming inverter capabilities, as well as DEFRs, will likely be part of this transformation. In May 2023, the New York State Public Service Commission (PSC) initiated a process to examine the need for resources to ensure the reliability of the CLCPA mandate for a zero-emissions electric grid by 2040. The PSC seeks to identify innovative technologies to ensure the reliability of a zero-emissions electric grid. Numerous other initiatives at both state and federal levels are in progress and may impact the grid of the future.

Energy Storage

Storage resources can help to fill in voids created by reduced output from renewable resources. However, sustained periods of reduced renewable generation can rapidly deplete storage capabilities. NYISO has implemented its Co-Located Storage Resources model to allow wind or solar resources that are interconnected with an energy storage resource the ability to participate in the markets while respecting a shared interconnection limitation. NYISO is developing a model for hybrid storage resources to allow multiple technologies at the same point of interconnection to participate in the market as a single resource. Additionally, the resource adequacy simulation tools (such as GE's MARS) used in system planning by NYISO and for setting the IRMs were enhanced to include energy-limited resources models that allow for charging and discharging and also include temporal constraints (e.g., hours/days or hours/month).

Capacity Transfers

The models used for NYISO's reliability planning studies include firm capacity transactions (purchases and sales) with the neighboring systems as a base-case assumption. Proposed projects that are in a more advanced stage are included. One such project is the 1,250 MW HVdc line from Québec to New York City, which is reflected in the LTRA summer total transfers starting in 2026. Additionally, the probabilistic model that NYISO uses to assess the adequacy of resources in the reliability planning processes employs several methods aimed at preventing overreliance on the external systems support. For example, NYISO employs limiting emergency assistance from neighbors by modeling a total limit of 3,500 MW, modeling five simultaneous peak days, modeling the long-term purchases and sales with neighboring control areas, and not modeling emergency operating procedure steps for the neighbors.

New York is fortunate to have strong interconnections with neighboring regions and has enjoyed reliability and economic benefits from such connections. As the energy policies in neighboring regions evolve, New York's imports and exports of energy could vary significantly due to the resulting changes in neighboring grids. The availability of energy for interchange is predicted to shift fundamentally as policy achievement progresses. As New York's and other regions' grids evolve, continuous monitoring and collaboration with our neighboring states will be required.

Transmission

Significant new transmission is being built across New York, but more investment is necessary to support, among other things, the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest.

Key transmission projects under development and accounted for in the reliability models include the following:

- The Northern New York Priority Transmission Project upgrading the transmission corridors from the renewable generation pocket in the north country to central New York
- The 1,250 MW Champlain-Hudson Power Express HVdc line from Hydro-Québec to New York City
- The AC Public Policy Transmission Projects that consist of upgrading transmission corridors in central New York and the lower Hudson Valley, which projects target completion of the majority of the components by December 2023
- The transmission project selected to address the Long Island Offshore Wind Expert Public Policy Transmission Need and that adds three new dc tie lines and a 345 kV backbone across western/central Long Island with an in-service date in 2030

Additionally, there are significant transmission projects either recently selected or under study that have not yet met the criteria to be in the reliability model. For instance, the PSC recently identified a new public policy transmission planning need for NYISO to solicit proposed solutions and that is intended to support the integration of 4.7 GW of wind resources in New York City.

Furthermore, in 2020, the PSC ordered the New York utilities to undertake planning assessments and make investment proposals to facilitate the cost-effective development of renewable and emissions-free resources while maintaining the reliability of New York's electric grid. The Coordinated Grid Planning Process (CGPP) was approved by the PSC in August 2023. The process is designed to assess the state's electric grid using a 20-year planning horizon. The CGPP is intended to identify electric grid expansions that can aid in unlocking renewable generation capacity and provide energy headroom for the purpose of meeting New York's clean energy goals while providing value to customers. Moreover, the CGPP is designed to identify opportunities for expansion of the bulk transmission system to advance the mandates of CLCPA. This provides another opportunity to inform the PSC's consideration of whether to establish a public policy transmission need for NYISO to solicit and evaluate proposed solutions.

Reliability Issues

The 2024 RNA, targeting completion in the fourth quarter of 2024, identifies transmission security violations of reliability criteria primarily driven by a combination of forecasted increases in peak demand, limited additional supply, and the assumed retirement of generation in New York City in response to state law and regulations. Accounting for these factors, the planned bulk power transmission system will not be able to securely and reliability serve the forecasted demand in New York City. When accounting for forecasted economic growth and policy-driven increases in demand, the New York City (Zone J) will be deficient starting in summer 2033 by as much as 17 MW for 1 hour and increasing to 97 MW for 3 hours in summer 2034 on the peak day during expected weather conditions. The Reliability Need occurs within the transmission district owned by Consolidated Edison Company of New York, Inc. ("Con Edison"). Con Edison is designated as the Responsible Transmission Owner in the NYISO's transmission planning process and required to submit a regulated backstop solution to address the need, which may be triggered if sufficient market-based solutions do not materialize.

Prior to the 2024 RNA, the NYISO completed the 2023 Q2 STAR on July 14, 2023. This assessment found a reliability need beginning in summer 2025 in New York City primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by the New York Department of Environmental Conservation (DEC) Peaker Rule. The reliability need is a deficiency in the transmission security margin. Specifically, the New York City zone is deficient by as much as 446 MW for a duration of nine hours on the peak day during expected weather conditions (95 degrees Fahrenheit) when accounting for forecasted economic growth and policy-driven increases in demand. To ensure the continued reliability of electric service in New York City, NYISO designated the generators on the Gowanus 2 & 3 and Narrows 1 & 2 barges as necessary for reliability to temporarily remain in operation after the Peaker Rule compliance date until permanent solutions to the need are in place, for an initial period of up to two years (May 1, 2027).

The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation and may lead to increasing reliability issues on the New York system. Reliability margins are shrinking. Generators needed for ERSs are planning to retire. Delays in the construction of new supply and transmission, higher-than-expected demand, and extreme weather could threaten reliability and resilience in the future. The

system is projected to become winter-peaking in the next decade due to electrification and decarbonization policies. Large loads are being proposed to interconnect to the system. New York's current reliance on neighboring systems is expected to continue through the next 10 years. A successful transition of the electric system requires replacing the reliability attributes of existing fossil-fueled generation with clean resources with similar capabilities. Such resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. New transmission is being built but more investment is necessary to support the delivery of offshore wind energy to connect new resources located in upstate to downstate load centers where demand is greatest.

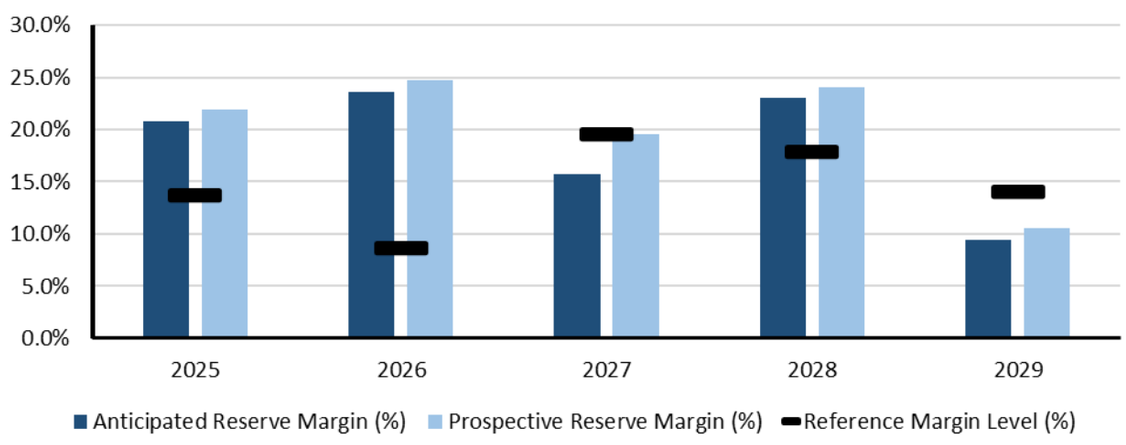


NPCC-Ontario

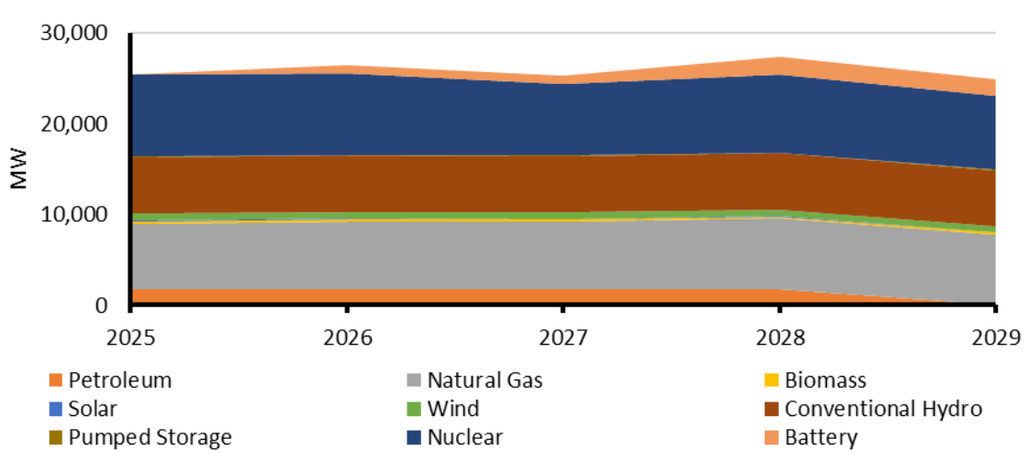
NPCC-Ontario is an assessment area in the Ontario province of Canada. The IESO is the Balancing Authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	23,385	23,860	24,264	24,627	25,248	26,038	26,473	27,373	27,974	28,789
Demand Response	1,791	1,914	1,914	1,914	1,914	1,914	1,914	1,914	1,914	1,914
Net Internal Demand	21,594	21,946	22,350	22,713	23,333	24,123	24,559	25,458	26,060	26,875
Additions: Tier 1	617	1,737	1,735	3,012	3,302	3,300	3,843	4,385	4,384	5,128
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	600	600	500	600	600	600	600	0	0	0
Existing-Certain and Net Firm Transfers	25,470	25,394	24,133	24,924	22,242	22,051	20,660	20,705	20,671	20,257
Anticipated Reserve Margin (%)	20.8%	23.6%	15.7%	23.0%	9.5%	5.1%	-0.2%	-1.4%	-3.9%	-5.5%
Prospective Reserve Margin (%)	22.0%	24.8%	19.5%	24.1%	10.5%	6.1%	0.8%	-0.5%	-2.9%	-4.6%
Reference Margin Level (%)	13.7%	8.6%	19.5%	17.8%	14.1%	9.4%	17.2%	8.1%	6.8%	8.5%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- While potential reserve margin shortfalls are forecast for 2027 and 2029, they are mainly driven by changes in the IESO's resource adequacy assessment methodology since the *2023 LTRA*. Last year, reserve margin calculations included the continuation of existing resources (following contract expiry) for the entire outlook period. For this LTRA, reserve margins reflect the contribution of existing resources only until the end of their contract or commitment period. This change to the methodology is more conservative and helps to better identify system needs in the IESO's planning assessments to establish resource acquisition targets and address anticipated needs.
- The IESO has two capacity sharing agreements with Hydro-Québec providing firm summer capacity, which will help to address future shortfalls this decade.
- The IESO has completed a broad set of actions to secure new capacity for this decade to ensure that Ontario's power system needs are met during a period of nuclear retirements and refurbishments and economy-wide demand growth. This includes securing long-term commitments amounting to 2,195 MW of new capacity to be on-line by 2028, with early operation incentives anticipated to bring a portion on-line as early as 2027 to help alleviate the reserve margin gap.
- The annual capacity auction, which helps to meet needs in the short term by securing capacity for up to one year at a time, has historically secured more capacity than targeted. Trends suggest that this should continue, as the November 2024 auction (which will help to ensure reliability through summer 2025 and winter 2025–2026) also secured more capacity than targeted.
- The IESO is taking steps that will address future shortfalls around the end of this decade and heading into the 2030s. The next round of medium- and long-term procurements was recently launched to ensure that capacity and energy needs continue to be met. The second medium-term procurement aims to re-commit existing resources with contracts expiring over the 2026–2029 period, while the second long-term procurement aims to secure capacity and energy from new resources (to be online as early as 2029), to meet needs emerging in the early 2030s.
- The IESO is also responsible for implementing new provincial policy as outlined in the Ontario government's July 2023 Powering Ontario's Growth report, which includes developing new nuclear projects, transmission expansions, and expanded conservation and demand management programs. The IESO will also incorporate changes stemming from the federal release of the final Clean Electricity Regulations, anticipated toward the end of 2024.

NPCC-Ontario Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Petroleum	1,695	1,695	1,695	1,695	5
Natural Gas	7,275	7,465	7,465	7,847	7,761
Biomass	297	294	257	209	209
Solar	100	100	100	100	100
Wind	743	722	711	711	602
Conventional Hydro	6,215	6,212	6,212	6,212	6,202
Pumped Storage	38	38	38	38	38
Nuclear	9,008	9,008	7,895	8,639	8,142
Battery	118	998	996	1,886	1,885
Total MW	25,487	26,531	25,368	27,336	24,944

Planning Reserve Margins

The ARM falls below the RML starting in 2027. While expected nuclear retirements, the ongoing nuclear refurbishment program, and demand growth are resulting in increased needs this decade, the reserve margin shortfalls indicated in 2027 and 2029 are primarily driven by the change in the IESO's resource adequacy assessment methodology described above.

Mid-decade capacity needs that were identified in the 2022 *Annual Acquisition Report* have been met through a series of competitive procurements. Since May 2023, the IESO has secured over 3,600 MW of new capacity from battery storage, natural gas, and biogas facilities, expected to come on-line between 2025 and 2028. In addition, the 2023 capacity auction secured 1,867 MW of summer capacity and 1,311 MW of winter capacity above targets of 1,400 and 850 MW, respectively. The IESO continues to actively procure existing and new resources to meet longer-term needs, using the mechanisms in the Resource Adequacy Framework.

Ongoing refurbishments at Bruce Nuclear Generating Station (NGS) and Darlington NGS will see between one and three reactors concurrently off-line through Summer 2033. Refurbishments remain on or ahead of schedule and outages continue to be managed to limit impacts to the grid. Following the return to service of refurbished units at Bruce, each unit is expected to be uprated, with the additional capacity anticipated to be available in the early 2030s.

The Ontario government has also announced a plan to deliver three additional small modular reactors in addition to the 300 MW unit already underway (anticipated on-line in 2029). The provincial government's July 2023 Powering Ontario's Growth plan directed the IESO to conduct an impact assessment on potentially adding 4,800 MW of large-scale nuclear capacity to Bruce NGS. Approval was granted from the federal nuclear regulator in October 2024 to extend operation of four units at Pickering NGS (previously scheduled for decommissioning in 2025) through September 2026. The government is also supporting the refurbishment of the four units at Pickering, with refurbishment of the first unit anticipated to be completed in 2031.

To address resource adequacy needs emerging mid-decade due to the combined effect of nuclear retirements and refurbishments, as well as expiring generation contracts, the IESO has employed competitive acquisition mechanisms from the Resource Adequacy Framework in part via the capacity auction referenced above. The IESO's first long-term procurement concluded in May 2024 and secured long-term commitments from 10 battery storage facilities for 1,784 MW of new capacity and three natural gas/biogas facilities for 411 MW of new capacity. Facilities are anticipated to be in service as early as May 2027.

The IESO calculates the reserve margin requirement on an annual basis and publishes this in the Annual Planning Outlook (APO). The requirement is calculated for each year for net demand at the time of the annual demand peak to provide an LOLE that is at or below 0.1 days per year. The reserve margin requirement in the *2024 LTRA* is derived from the capacity requirement in the 2024 APO, plus any material changes to demand and supply following APO publication.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Energy adequacy assessments are conducted annually for the APO by using a deterministic approach in the IESO's economic dispatch model. In addition, the IESO's capacity adequacy assessments consider the system's ability to serve load in all hours of the year (i.e., during peak hours as well as non-peak load hours).

As demand requirements increase, nuclear refurbishments continue, and some units at the Pickering NGS retire in 2024, Ontario's energy needs are expected to be met this decade by the resources secured through the IESO's recently completed procurements. The second medium-term procurement, which was recently launched, aims to secure capacity and energy from existing resources reaching contract end; this is expected to help alleviate energy risks in the latter half of this decade. The second long-term procurement that is underway aims to acquire new capacity and energy-producing resources and is anticipated to alleviate energy risks in the early 2030s.

Factors that could increase energy adequacy risks include aging resources and the potential for decreased performance, market exit of resources reaching contract end, extreme weather, and decarbonization policies and risks presented by new resources, including in-service delays or a high risk of forced outages during the initial period of operation. Deliverability challenges for new resources and long lead times required to build new transmission may also increase energy adequacy risks. Demand-side factors include materialization of data centers, increased industrial automobile production and EV supply chain loads, and climate change impacts on weather-sensitive load.

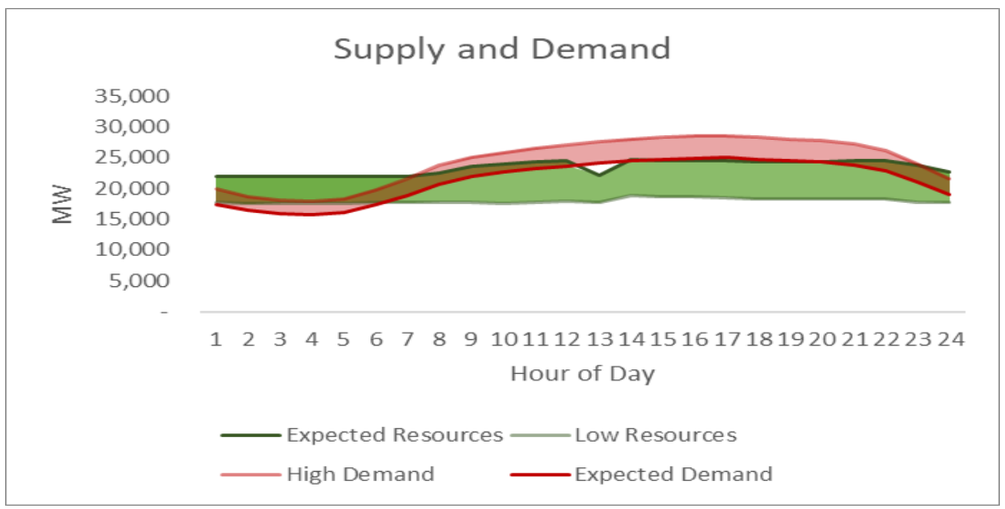
Looking forward, with the federal government's proposed Clean Electricity Regulations to decarbonize Canada's electric system by 2050, the IESO is assessing the role of natural gas generation as a flexible resource in the interim as new sources of non-emitting supply are added to the system.

The IESO conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and to comply with NPCC and NERC reliability requirements. Results from the 2024 ProbA are shown in the table on the next page. The low risk of unserved energy is concentrated in the summer peak period, which typically occurs in late August.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	72.16	**0.04**	**4.97**
EUE (PPM)	0.49	**0.00**	**0.03**
LOLH (hours per year)	0.44	**0.00**	**0.01**
Operable On-Peak Margin	-6.7%	**13.3%**	**9.5%**

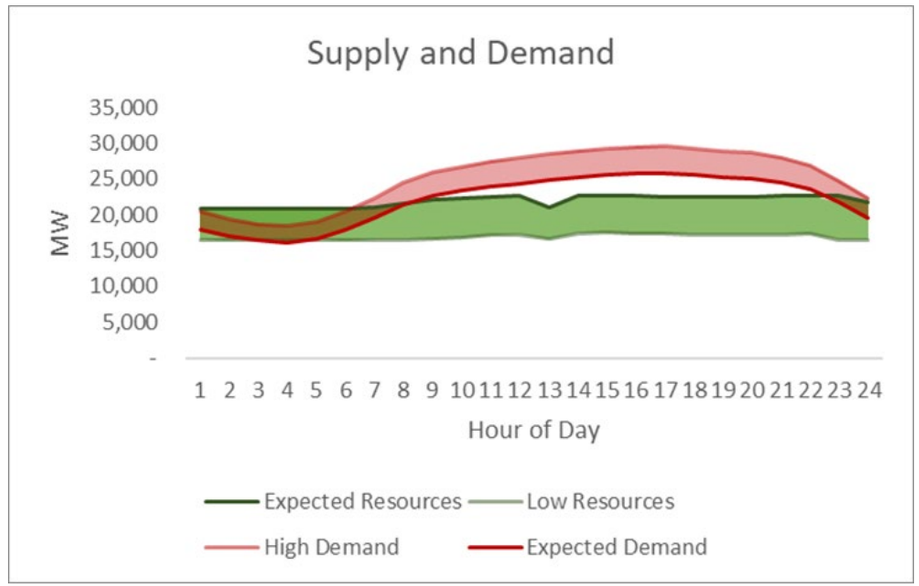
* Provides the 2022 ProbA Results for Comparison

Hourly demand and resource projections for a representative summer risk-day in 2026 are shown in the figure below. Expected resource contributions are not sufficient to meet expected demand on the risk day. The risk could be exacerbated by either a lower-than-expected resource contribution event or a higher-than-expected demand event, with greater risk being due to a larger variability in resource contribution. There is expected strain on the system from the hours beginning 12:00 p.m. through 8:00 p.m. If resource contributions are less than expected, strain on the system at expected demand conditions could be seen for almost all hours of the day beginning at 7:00 a.m. Reliance on external assistance may be necessary during peak conditions.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

In 2028, the EUE and LOLH are higher than 2026. Risk occurs during the same summer peak period but also during winter peak conditions in December. Demand growth that is forecasted to occur between 2026 and 2028 contributes to higher loss-of-load risk compared to the 2026 result. The risk day in 2028 has the same drivers as the 2026 result noted above.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2028

Demand

Forecasted demand for this *2024 LTRA* outlook period (relative to the *2023 LTRA* outlook period) indicates 10% higher annual energy demand, 8% higher summer peak demand, and 9% higher winter peak demand.

With an expanding agricultural and greenhouse sector, along with increasing electricity use for home heating and transportation, summer and winter peaks are anticipated to converge over the forecast period, leading Ontario to be dual-peaking by 2030. In the near term, the peak magnitude is expected to increase slightly as the province exits the remnants of the post-pandemic inflationary cycle, and new industrial projects supporting decarbonization begin commercial operation. Over this assessment period, the IESO projects total internal demand growth to increase at a compound annual growth rate of 2.34% for summer and 2.75% for winter. Offsetting the growth in demand are reductions from conservation, including savings from EE programs and codes and standards regulations, electricity price responsiveness and increased output by embedded generation.

Ontario's Industrial Conservation Initiative (ICI) acts as a critical peak pricing program leading to reductions in demand at peak and is expected to reduce around 1,500 MW if the hour of annual system peak demand occurs in the summer or around 1,000 MW if it occurs in the winter. It is expected to scale based on increased industrial growth in future years, with reductions in 2034 of 2,000 MW for a summer peak demand hour and over 1,400 MW for a winter peak demand hour.

Demand-Side Management

DR capacity, from both dispatchable loads and hourly DR resources (e.g., residential or commercial and industrial load), is procured through the IESO's annual capacity auction. Starting with the 2023 capacity auction, the IESO implemented a capacity qualification process for all resource types eligible to participate, which applies resource-specific calculation methodologies to determine the amount of unforced capacity (UCAP) each resource is eligible to offer into the auction.

In June 2023, the IESO launched Peak Perks, a residential DR program where participants help reduce demand by up to 150 MW through brief, time-limited thermostat adjustments during periods of peak electricity demand in the summer months.

In July 2023, the IESO launched an interruptible rate pilot to provide large-load customers with an interruptible rate in exchange for agreeing to temporarily reduce demand when directed by the IESO. The pilot spans a three-year period and up to 15 events of up to four-hour duration can be called, primarily in the day-ahead timeframe but also on shorter notice.

Forecast savings from the IESO's 2021–2024 Conservation and Demand Management Framework were included in the forecast and resulted in a decrease in demand. Savings from the 2021–2024 CDM framework are expected to persist beyond the end of 2024. In February 2024, Ontario's minister of energy asked the IESO to examine options and analysis for a post-2024 EE framework and programs.

Distributed Energy Resources

The IESO estimates that contracted DERs contributed more than 3,400 MW of capacity and 5.3 TWh of energy in 2023, more than half of which is solar PV, one-third wind, and modest contributions from hydroelectric and biomass resources. While the IESO has little insight into uncontracted DERs, it has observed energy contributions of approximately 2 TWh in 2023.

Generation

Recent generation procurements are provided in the PRM section.

The transmission-connected supply mix in Ontario has shifted over the past decade from having only synchronous generation facilities to one with more IBRs including wind, solar, and storage. Previous assessments performed by the IESO indicate that Ontario is expected to have sufficient inertia and frequency response to ensure stable operation up to 2025.

Going forward, the addition of over 2,900 MW of new battery storage resources in the next few years will increase the proportion of IBRs on the system. With the shift toward a higher proportion of IBRs, further areas that will be explored include the sufficiency of the resource mix to provide system inertia, primary frequency response, operating reserve, ramping capability, reactive support, and voltage control. If needs are identified, the IESO's procurements may be used as one avenue to acquire resources that can provide the required services.

The IESO has also been taking a proactive approach to dealing with challenges posed by IBRs. This includes working to optimize the location of IBR resources acquired through the IESO's procurements to minimize performance issues and initiating a review of the IESO's Market Rules to align with the latest IEEE 2800 standard, which aims to establish uniform technical minimum requirements for interconnection, capability, and lifetime performance of IBRs.

Energy Storage

By May 2028, over 2,900 MW of new battery storage resources are expected to come on-line, including the 250 MW/1,000 MWh Oneida battery storage facility (expected to be operational in June 2025), and 2,714 MW of battery storage resources secured through the IESO's first set of long-term procurements. Of this, 930 MW is expected to reach commercial operation by May 2026 and the remaining 1,784 MW by May 2028. These standalone battery storage resources (with a minimum four-hour duration) are expected to support the reliable operation of Ontario's electric system through the ability to be dispatched by the IESO and ramp up and down quickly. The resources are also located in areas of Ontario where transmission security or resource adequacy needs were identified.

Newly acquired energy storage facilities through the IESO's first set of long-term procurements will be required to be available during peak hours.

Capacity Transfers

Firm capacity imports and exports with neighboring jurisdictions are included in the IESO's planning studies. For non-firm imports, the IESO assumes a limited amount for the purposes of its reliability assessments. Non-firm imports are assumed to be 250 MW for summer and 240 MW for winter, an amount considered likely to flow throughout the year, including under tight supply conditions and prices.

In November 2024, the IESO and Hydro-Québec finalized a new capacity sharing agreement for a swap of a minimum of 600 MW of capacity per season. Under this agreement, the IESO will deliver capacity

to Québec during the winter period and Hydro-Québec will deliver capacity to Ontario during the summer period. The agreement commences in the Winter 2024–2025 season and runs to October 2031, with an option for an extension for an additional three years. Other terms of the agreement are expected to include the option for the IESO to increase the minimum amount provided to Québec each year and to bank any amount of the 600 MW from Québec for use in a future summer period over the term of the agreement.

The 2023 capacity auction secured 300 MW of system-backed imports from Québec for the Summer 2024 obligation period. As part of the 2016 capacity sharing agreement between Ontario and Québec, the IESO may call on a total of 500 MW of firm imports from Hydro-Québec, which may be requested all in one summer or in smaller amounts over multiple summers. The IESO's recent assessments indicate the intention to utilize the 500 MW of firm imports from June to September 2027 to help meet resource adequacy needs. However, depending on the outcomes of the ongoing procurements and changes to Ontario's resource adequacy outlook, the IESO may choose to utilize this capacity in another year.

Transmission

The existing transmission system in northeastern Ontario has insufficient capability to reliably supply forecasted load growth; as such, the IESO has recommended several new transmission reinforcements in the region to address this need. Several of the recommended reinforcements are in the early project development stage and one is undergoing a transmitter selection process.

The IESO recently recommended additional transmission reinforcements in southwest Ontario to support the area's medium-term needs, including a double circuit, 230 kV line from Lambton transmission station to Chatham substation, expected in-service by 2028, and a new 500 kV transmission line connecting Longwood and Lakeshore transmission stations, to be in-service by 2030. These projects will ensure that transfer capability continues to be sufficient as additional load continues to connect in the area.

Reliability Issues

Nuclear refurbishment over the next decade is a major resource risk that requires additional attention. The IESO has regular meetings with nuclear operators to assess probable delays and take appropriate mitigation actions.

For long-term planning purposes, the IESO carries an additional level of nuclear refurbishment reserve to account for the risk of refurbishment delays and increased forced outage rates pre- and post-refurbishment. In addition, advanced outage approvals are provided solely when Ontario is adequate under extreme weather.

Other factors that may pose reliability risks include supply chain issues, conditions in neighboring jurisdictions, extreme weather, decarbonization-driven changes to supply and demand, policy and regulatory uncertainty, asset health, and potential market exit of existing resources.

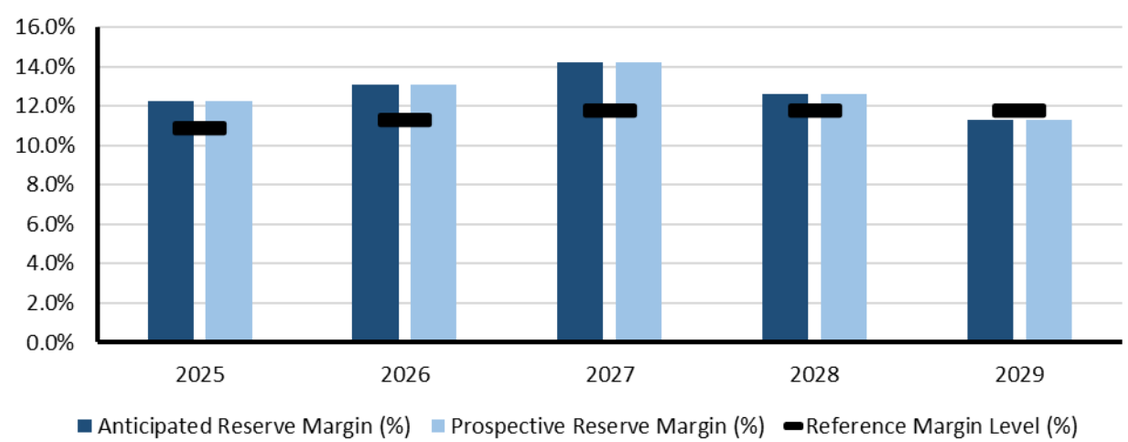


NPCC-Québec

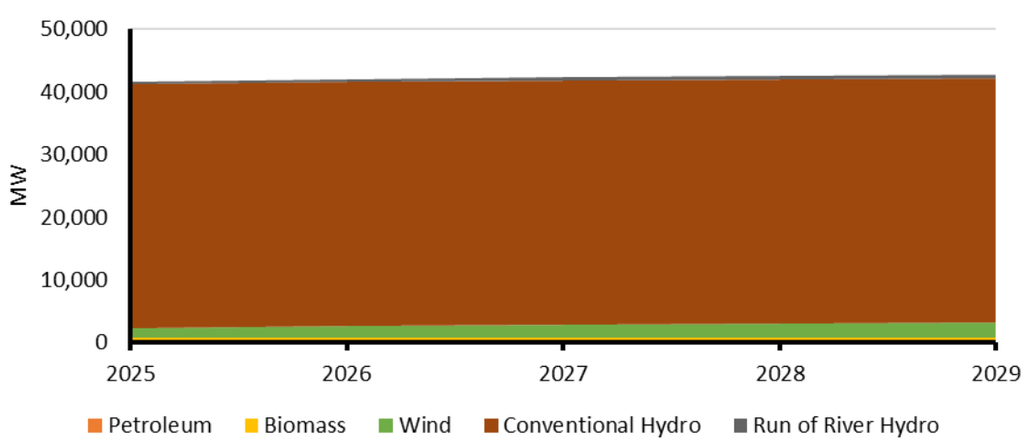
The Québec assessment area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of 8.5 million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVdc ties, radial generation, or load to and from neighboring systems.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	41,497	41,954	42,476	43,385	44,070	44,784	45,577	46,635	47,828	49,041
Demand Response	4,732	4,896	5,068	5,258	5,322	5,377	5,388	5,388	5,388	5,388
Net Internal Demand	36,765	37,058	37,408	38,127	38,748	39,408	40,189	41,247	42,440	43,652
Additions: Tier 1	73	469	665	835	1,016	1,016	1,016	1,016	1,016	1,016
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-390	-145	455	455	455	600	0	0	0	0
Existing-Certain and Net Firm Transfers	41,185	41,429	42,066	42,103	42,103	42,256	41,656	41,656	41,656	41,656
Anticipated Reserve Margin (%)	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
Prospective Reserve Margin (%)	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
Reference Margin Level (%)	10.9%	11.3%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM and PRM remain above the RML until 2029 (winter 2029–3030).
- A total of 4,048 MW wind generation capacity (1,016 MW capacity value at peak time) is expected to be in service by 2030.
- Two new transmission projects connecting Québec with New England and New York are expected to be in service by the end of 2025 and May 2026, respectively.

NPCC-Québec Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Petroleum	429	429	429	429	429
Biomass	400	400	400	400	400
Wind	1,449	1,807	2,002	2,173	2,354
Conventional Hydro	38,925	38,962	38,999	39,036	39,036
Run of River Hydro	446	446	446	446	446
Total MW	41,648	42,043	42,276	42,483	42,664

NPCC-Québec Assessment

Planning Reserve Margins

The ARM is based on existing and anticipated generating capacity and firm capacity transfers. The Québec area projects an ARM above the RML over the first five winters of the assessment period (2024–2025 to 2028–2029). The ARM is under the RML for the winters 2029–2030 to 2034–2035 mainly due to the demand growth.

The RML is derived from the NPCC 2023 Québec Balancing Authority Area Comprehensive Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee on December 5, 2023. The demand uncertainty captured in the reserve ratio reflects both weather and economic uncertainty. The methods and assumptions can be found in the *Comprehensive Review* report available on the NPCC website.

The assumptions used for this assessment, including demand forecast and resources, are consistent with the Hydro-Québec 2023 Supply Plan update, which was filed with the Régie de l'énergie on November 1, 2023.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

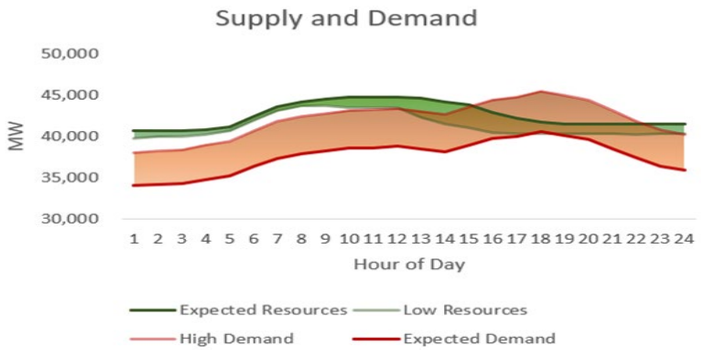
The main energy risk for the Québec area is associated with a series of dry years, hence the energy reliability criterion established by the Régie de l'énergie. This risk surpasses the energy risk associated with the other renewable resources over the horizon of this study. The potential impact of climate change on the water inflows could be an issue for energy reliability and is therefore the subject of various ongoing internal studies.

Hydro-Québec conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and comply with NPCC and NERC reliability requirements. Results from the 2024 ProbA are shown in the table below. The low risk of unserved energy is concentrated in the winter peak period, which typically occurs in late January to early February.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**8.21**	**4.97**
EUE (PPM)	0.00	**0.04**	**0.03**
LOLH (hours per year)	0.00	**0.01**	**0.01**
Operable On-Peak Margin	-2.3%	**9.8%**	**11.9%**

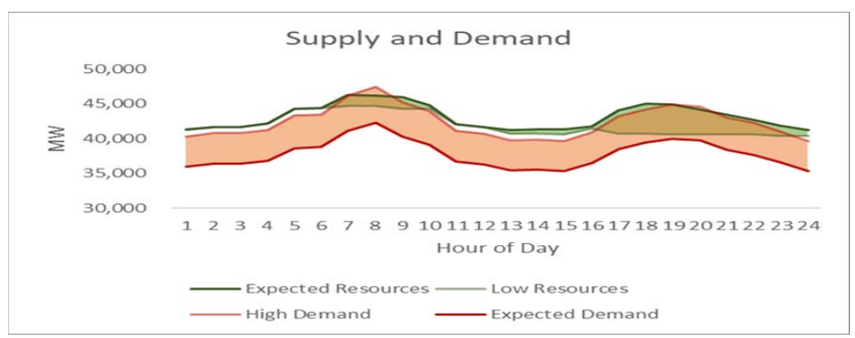
* Provides the 2022 ProbA Results for Comparison

Hourly demand and resource projections for a typical winter risk day in 2026 are shown in the figure below. Although expected resource contribution is expected to be enough to meet expected demand, there is risk that above-normal demand could exceed resources. Demand could be 10–15% higher than expected, which could strain the system from the hours beginning 3:00 p.m. through 10:00 p.m. Also, if resource contributions are less than expected, the peak hour beginning at 6:00 p.m. could lead to a loss-of-load situation. Reliance on external assistance may be necessary in these events.



Hourly Probabilistic Assessment Results | Representative Winter Risk Day 2026

Hourly demand and resource projections for a typical winter risk day in 2028 are shown in the figure below.



Hourly Probabilistic Assessment Results | Representative Winter Risk Day 2026

Demand

The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use sector peak demands is the total monthly peak demand.

Demand-Side Management

The Québec area has various types of DR resources specifically designed for peak shaving during winter operating periods. The first type of DR resource is the interruptible load program that is mainly designed for large industrial customers; it has an impact of 2,784 MW on winter 2024–2025 peak demand. The area is also expanding its existing interruptible load program for commercial buildings, which will grow from 611 MW in 2024–2025 to 889 MW by the end of the period study. Another similar program for residential customers is in operation and should gradually rise from 166 MW for Winter 2024–2025 to 621 MW for Winter 2028–2029.

New dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 371 MW for Winter 2024–2025 and 445 MW for Winter 2034–2035. Moreover, data centers specializing in blockchain applications are required to reduce their demand during peak hours at Hydro-Québec's request. Their contribution as a resource is expected to be around 269 MW over the study period. Finally, another DR resource consists in a voltage reduction scheme allowing for a 250 MW peak demand reduction. EE and conservation programs are integrated in the assessment area's demand forecasts.

Distributed Energy Resources

Total installed BTM capacity (solar PV) is expected to increase to 862 MW in 2035. Solar PV is accounted for in the load forecast. Nevertheless, since Québec is a winter-peaking area, DERs' on-peak contribution ranges from 2 MW for Winter 2024–2025 to 5 MW for the last winter period. No potential operational impacts of DERs are expected in the Québec area considering their low contribution.

Generation

Four wind projects with a total installed capacity of 4,000 MW are expected to be commissioned during the assessment period. The first project, Apuiat (204 MW), is expected to be commissioned in 2024–2025. The second project (1,144 MW divided into 6 wind farms) is expected to be commissioned in December 2026. The third project is Des Neiges (1,200 MW) and is divided into three phases (400 MW each). The first phase is expected to be operational in the winter of 2026–2027. The second and third phases are expected to be in service for the 2027–2028 and 2028–2029 winters, respectively. The fourth project is made of 1,500 MW divided into 8 wind farms, which are expected to be operational in the winters of 2027–2028, 2028–2029 and 2029–2030, depending on the location.

In addition to wind projects, unit replacement projects at existing hydroelectric facilities are being studied. Up to 2,000 MW of capacity could be added by replacing generating units with most recent models, as outlined in Hydro-Québec's Action Plan 2035.

Energy Storage

No energy storage facilities are planned to be commissioned during the assessment period.

Capacity Transfers

The governments of Québec and Ontario have signed an MOU of an agreement that allows a seasonal capacity exchange between the two areas for the next seven years except for the year 2027 (no exchange is allowed). The technical details of the agreement will be completed by Fall 2024 and will be in place from Winter 2024–2025 to winter 2030–2031. This agreement will be firm and allow Québec to import 600 MW from November to April. In summer, Québec will export 600 MW of firm capacity to Ontario from May to October.

Transmission

Appalaches-Maine Interconnection

This project, expected to increase transfer capability between Québec and Maine by 1,200 MW, has resumed construction. The project will connect to the New England Clean Energy Connect project (NECEC) in Maine. It involves the construction of a ±320 kV dc transmission line about 100 kilometers (62 miles) long from the Des Appalaches 735/230 kV substation to the Canada-United States. border. From the international border crossing, the dc transmission line will be extended 145 miles to a substation in Lewiston, ME, where the power will be converted from dc to ac. The project in Québec also includes the construction of an dc to dc converter at the Des Appalaches substation and triggers the need of thermally upgrade two 735 kV lines in the south of the system. The project is expected to be in service in December 2025.

Hertel-New York Interconnection (CHPE)

This project, expected to increase transfer capability between Québec and New York by 1,250 MW, is under construction. It involves the construction of a ±400 kV dc underground transmission line about 60 kilometers (37 miles) long from the Hertel 735/315 kV substation just south of Montréal to the Canada-United States border. The project will connect to the Champlain Hudson Power Express project (CHPE) in New York state. From the international border crossing, the dc transmission line will be extended 339 miles to a substation in Astoria, NY, where the power will be converted from dc to ac. The project in Québec also includes the construction of an ac to dc converter at the Hertel substation. The project is expected to be in service in May 2026.

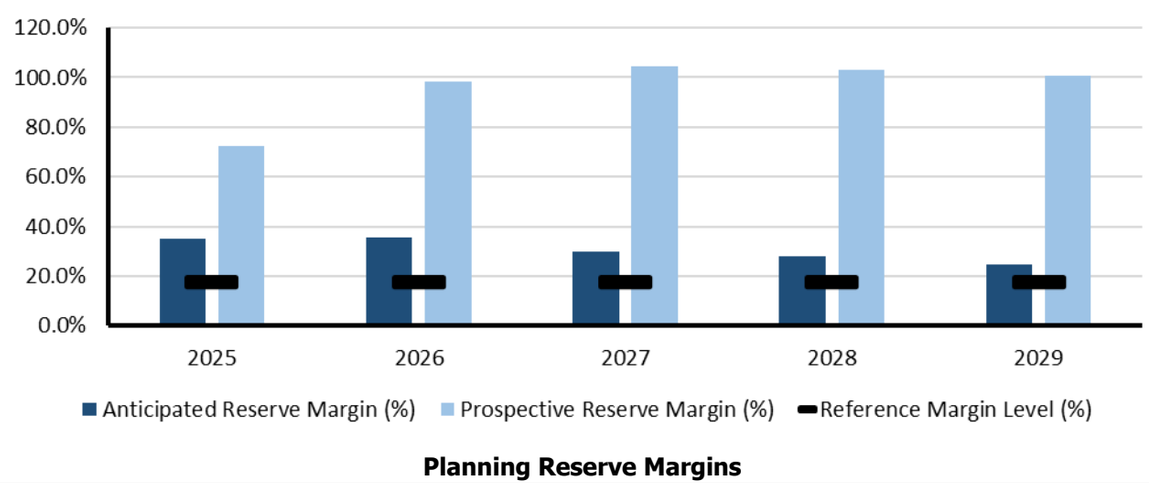


PJM

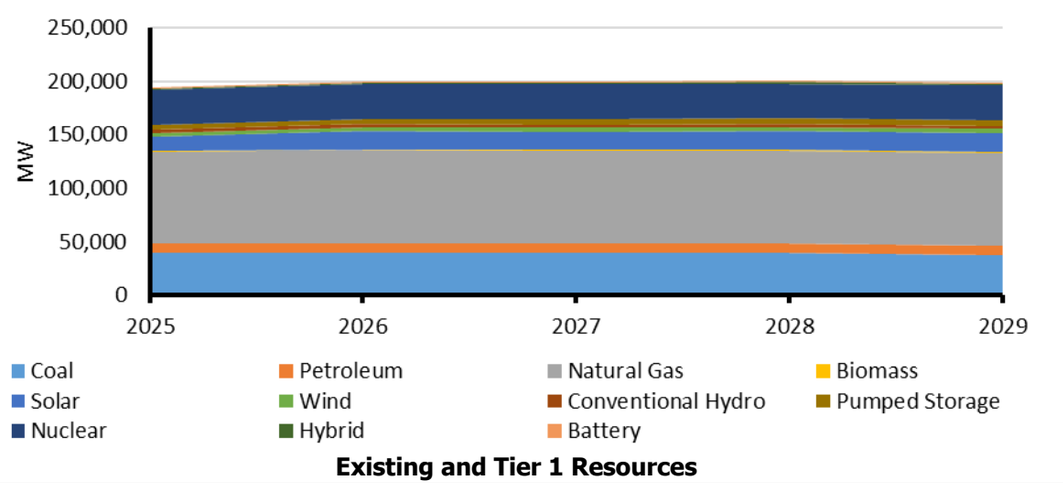
PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	153,493	156,803	159,859	162,972	165,681	167,873	170,008	172,109	174,366	176,822
Demand Response	7,554	7,693	7,808	7,913	8,000	8,083	8,162	8,230	8,312	8,400
Net Internal Demand	145,939	149,110	152,051	155,059	157,681	159,790	161,846	163,879	166,054	168,422
Additions: Tier 1	11,056	17,047	17,139	17,784	17,911	18,155	18,155	18,155	18,155	18,155
Additions: Tier 2	55,112	93,845	112,827	122,781	127,059	131,113	131,287	133,652	133,652	133,652
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	4,502	4,347	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	185,828	185,270	180,552	180,552	178,577	178,577	178,577	178,577	178,577	178,577
Anticipated Reserve Margin (%)	34.9%	35.7%	30.0%	27.9%	24.6%	23.1%	21.6%	20.0%	18.5%	16.8%
Prospective Reserve Margin (%)	72.4%	98.3%	104.7%	103.3%	100.5%	96.5%	94.1%	92.9%	82.1%	79.5%
Reference Margin Level (%)	17.7%	17.7%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the RML until 2034 when it falls below the 17.6% RML level.
- PJM implemented a number of changes to the 2023 load forecasting process to improve model accuracy, switching from an annual to monthly end-use model for PJM's sector models to better determine heating, cooling, and other non-weather-sensitive load and moving to an hourly model to better capture new technologies and peak shifting. Additionally, higher expectations for data center loads now incorporate 15-year forecasts from impacted electric distribution companies (EDC).
- PJM's review of recent policies (e.g., state laws and federal environmental initiatives) indicates over 32 GWs of potential deactivations through 2034. The pace of retirements is being driven in large part by these state laws and federal environmental initiatives that create a clear near-term, date-certain requirement for generation to comply or retire. Conversely, there are multiple mandates with renewable portfolio standards (RPS) that account for the majority of over 150 GWs submitted projects.

PJM Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	39,735	39,735	39,325	39,325	37,747
Coal*	39,394	39,394	33,313	28,240	25,124
Petroleum	8,810	8,514	8,514	8,514	8,117
Natural Gas	85,541	87,245	87,245	87,245	87,245
Natural Gas*	85,541	87,245	87,228	87,228	87,228
Biomass	928	928	928	928	928
Solar	13,349	16,770	16,908	17,621	17,754
Wind	3,017	3,512	3,507	3,507	3,507
Conventional Hydro	2,934	2,922	2,934	2,934	2,944
Pumped Storage	5,189	5,189	5,189	5,189	5,189
Nuclear	32,535	32,535	32,535	32,535	32,535
Hybrid	1,315	1,742	1,739	1,739	1,739
Battery	393	982	982	994	994
Total MW	193,747	200,074	199,807	200,532	198,699
Total MW*	193,406	199,733	193,779	189,430	186,060
*** Capacity with additional generator retirements.** Generators that are forecasted to retire by PJM are removed from the resource projection where marked.					

PJM Assessment

Planning Reserve Margins

The ARM does not fall below the RML in PJM until 2034. PJM's growing demand profile and a change in resource mix that favors VERs, however, present a new level of risk.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

PJM is forecasting around 30% installed reserves (including expected committed demand resources), which is well above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. Due to the current low penetration of energy-limited and VERs in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand. To address future reliability concerns due to growing VER penetration and limitations associated with the performance of those resources, PJM's Effective Load Carrying Capability methodology calculates the reliability and energy contribution of limited and variable resources.

Some of PJM's assumptions for determining the resource mix to use in the ProbA differ from those used in developing the LTRA. Only a portion of the Tier 1 resource additions are used in the ProbA to more accurately reflect historical rates of development. Additionally, more generator retirements are used in the ProbA based on PJM's generator forecasting. These assumptions are more consistent with the assumptions included in official studies performed by PJM to support its capacity market. In addition, the information in the ProbA for winter seasons refers to the Winter 2026–2027 and Winter 2028–2029 because PJM's studies are based on "delivery years," which start on June 1 of a year and end on May 31 of the subsequent year.

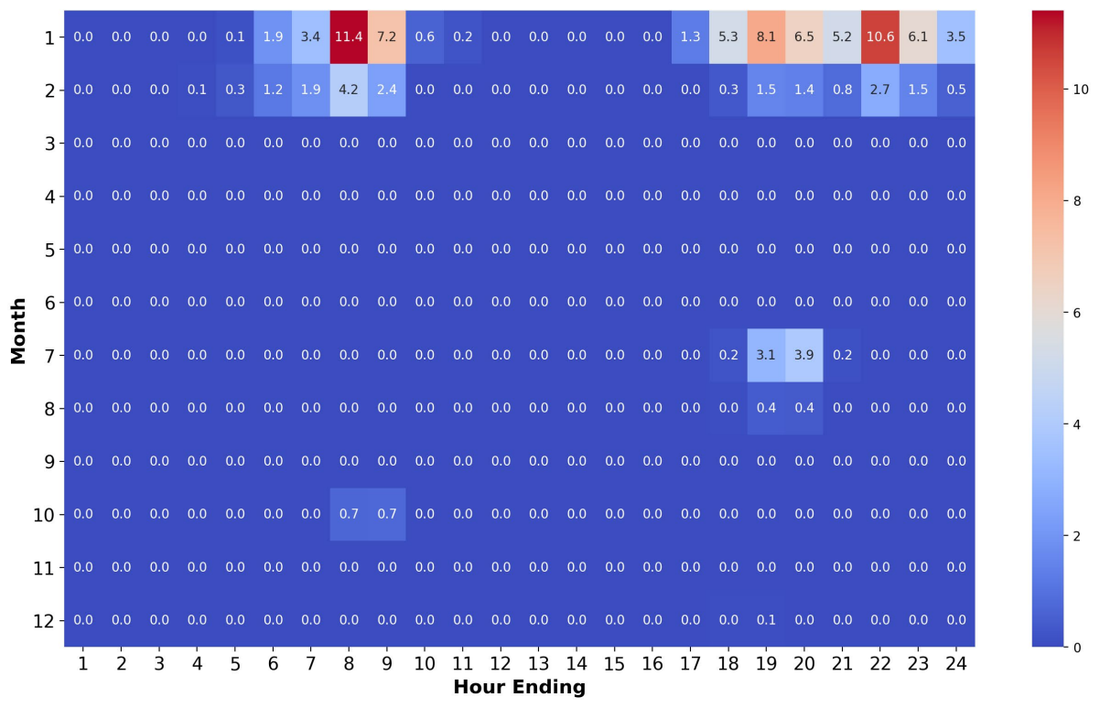
Results of the 2024 ProbA are provided in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**537.52**	**1043.44**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.11**	**0.22**
Operable On-Peak Margin	29.0%	**17.8%**	**17.7%**

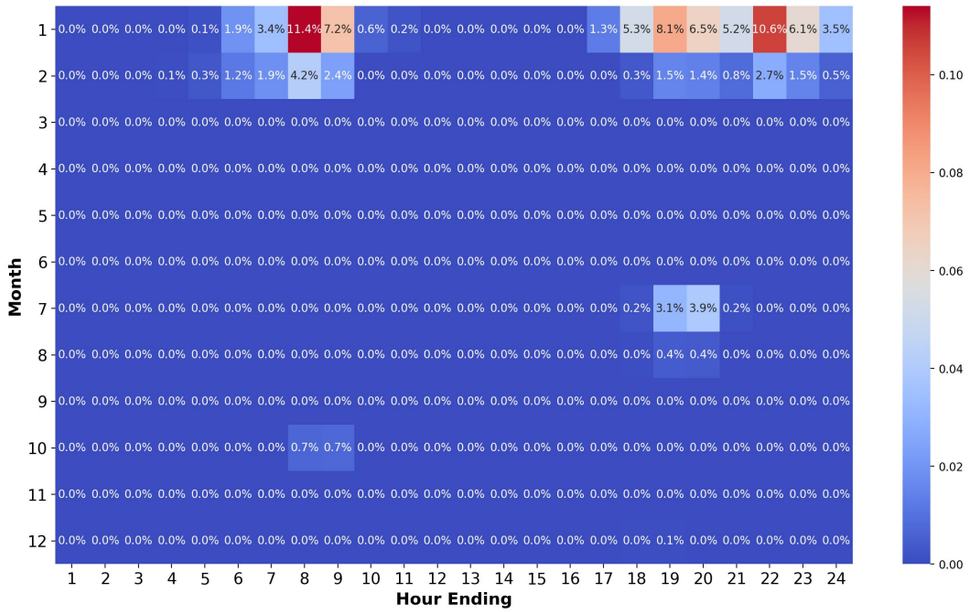
* Provides the 2022 ProbA Results for Comparison

In both 2026 and 2028, most EUE and LOLH are concentrated in the winter months (especially January), as shown in the following EUE heat maps. The risk occurs in days when temperatures are very low, which results in high loads across the assessment area. If resource performance were to occur at the levels expected during average winter days, the system should be able to serve these high loads. However, resource performance from thermal resources on very cold days, especially natural gas resources, is more likely to be poor. This, coupled with poor performance from solar resources, results in very low total electricity supply and causes loss-of-load events in the ProbA analysis. The winter load-loss events tend to occur during morning and evening demand peaks and coincide with poor thermal performance and poor solar performance.

The smaller shares of EUE and LOLH observed in the summer period for 2026 and 2028 are associated with high temperatures and high loads across the assessment area that drive load-loss events in the evening (hours ending 19 and 20) as grid-connected and BTM solar resource output declines. Low performance of wind resources and, to a lesser extent, slightly worse performance of thermal resources, also contribute to the load-loss events in the analysis.



2026 EUE Heat Map (Share of Annual EUE in %)



2028 EUE Heat Map (Share of Annual EUE in %)

PJM implemented capacity reforms (approved by FERC) at the start of 2024, which include using the loss-of-load model employed to perform the ProbA, as well as accreditation reforms based on the risk patterns identified by said model, for the capacity auctions starting with delivery year 2025–2026.

Demand

PJM is experiencing large growth in data centers that are in turn driving higher demand forecasts. Loudoun County, Virginia, in the PJM assessment area, is home to "Data Center Alley," the largest concentration of data centers in the world. Electrification in transportation, heating, and industrial sectors is also spurring demand growth.

The PJM Interconnection produces an independent peak load forecast of total internal demand using econometric regression models with daily load as the dependent variable and independent variables including calendar effects, weather, economics, and end-use characteristics. PJM annually reviews its load forecast methodology and implements changes when improvements are identified.
Summer peak load growth in PJM is projected to average 1.6% per year over the next 10-year period and 1.6% over the next 15 years. The PJM summer peak is forecasted to be 176,822 MW in 2034, a 10-year increase of 25,575 MW, and reaches 190,752 MW in 2039, a 15-year increase of 39,505 MW. Annualized 10-year growth rates for individual zones range from 0% to 5.5% with a median of 0.5%.

Winter peak load growth for PJM is projected to average 1.9% per year over the next 10-year period and 1.8% over the next 15 years. The PJM regional transmission organization winter peak load in 2033–2034 is forecasted to be 163,069 MW, a 10-year increase of 28,410 MW, and reaches 176,195 MW in 2038–2039, a 15-year increase of 41,536 MW. Annualized 10-year growth rates for individual zones range from 0% to 5.0% with a median of 0.7%.

Net energy for load growth for PJM is projected to average 2.3% per year over the next 10-year period and 2.2% over the next 15 years. Total PJM energy is forecasted to be 1,021,955 GWh in 2034, a 10-year increase of 208,627 GWh, and reaches 1,120,928 GWh in 2039, a 15-year increase of 307,600 GWh. Annualized 10-year growth rates for individual zones range from 0.1% to 7.3% with a median of 0.7%.

Demand-Side Management

DR resources can participate in all PJM markets—capacity, energy, and ancillary services. DR is forecast to grow during summer peak season from 7,550 MW in 2025 to 8,400 MW in 2034.

Distributed Energy Resources

PJM expects 4,470 MW of solar DERs at the time of the peak in 2029 and 5,103 MW in 2034. The effects of solar DERs are included in the load forecast for PJM. No effect of solar DERs is incorporated in the winter load forecast since winter expected peak occurs after sundown.

Generation

Overall, new generation is coming on-line slower than anticipated. Generator retirements are outpacing the new generation replacing them. As a result, PJM could face future resource adequacy challenges, impacting system reliability and PJM's ability to serve load. PJM could be at risk of facing resource adequacy challenges if these trends continue. PJM has applied an 11% reduction to the nameplate value of Tier 1 resources to reflect the historical rate of slower-than-anticipated addition of new generation.

PJM reviews the progression of generation interconnection to understand overall developer trends more fully and their impact on the interconnection process. Of new and expanded generation resources submitted in Queue A (1999) through December 31, 2023, 74,294 MW (or 15.8%) reached commercial operation, 33,166 MW (or 7%) were withdrawn from the interconnection process after Interconnection Service Agreement (ISA) execution, and 1,560 MW (or 0.3%) were withdrawn after wholesale market participant agreement (WMPA) execution but before construction. Overall, 20.4% of projects that requested uprates to existing capacity reached commercial operation.

Stakeholders at the June 6, 2023, Interconnection Process Subcommittee meeting approved an issue charge to examine how to enhance transfer of CIRs, which allow new generation to interconnect as a capacity resource, from deactivating resources to new generation. The goal is to develop a solution that both improves the efficiency of the process and clarifies that it applies to all energy-injecting capacity resource types. The existing provisions in the PJM Tariff, and related defined terms included in the Reliability Assurance Agreement (RAA), governing the CIR transfer process will be clarified to reduce confusion as to which capacity resource types the transfer process applies.

PJM's existing installed capacity reflects a fuel mix consisting of approximately 48% natural gas, 22% coal, and 18% nuclear. Hydro, wind, solar, oil, and waste fuels constitute the remaining 12%. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility. Totaling nearly 125,000 MW of CIRs, renewable and hybrid fuels are changing the landscape of PJM's interconnection process. Solar energy makes up 40% of the new service requests in PJM's generation interconnection queue. State policies encouraging renewable generation are contributing to the rise in solar generation interconnection requests.

PJM's review of recent policies indicates over 32 GWs of potential deactivations through 2034. The pace of retirements is being driven in large part by state laws and federal environmental initiatives that create a clear near-term, date-certain requirement for generators to comply or retire. See *Energy Transition in PJM: Resource Retirements, Replacements, and Risks* (February 2023). Conversely, there are multiple mandates with RPS that account for the majority of over 150 GWs in submitted projects. Growing levels of intermittent and limited duration resources, such as wind, solar, and battery storage, do not replace conventional large-scale generation installations megawatt-for-megawatt but rather require multiple megawatts to replace one megawatt of dispatchable generation due to their limited availability in certain hours of the day and seasons of the year. Many megawatts from a range of generation technologies, available at different times, are required to replace a megawatt of thermal generating capacity. Looking out over the next 8 to 10 years of the energy resource transition, maintaining an adequate level of generation resources with operational and physical characteristics that support reliability will be crucial for PJM's ability to serve electrical demand reliably.

Energy Storage

Energy storage development continues in PJM. As solar generation increases in PJM, growth of storage is expected to follow since storage devices are frequently co-located with solar projects. Efficient grid operations in an era of rapid renewable energy resource growth will require greater system flexibility. Energy storage can offer grid operators another tool to maintain stable power supply under varying wind and solar power output driven by weather conditions or unit outages. Storage can also improve grid efficiency by increasing utilization of existing transmission lines. PJM continues to work with members, Department of Energy (DOE) national laboratories, and other industry entities to advance the use of energy storage and, in particular, enable its participation in PJM markets.

Today, there are approximately 177 GWs of solar, wind, battery, and hybrid in the PJM interconnection queue. Hybrid resources make up approximately 26 GWs and standalone storage makes up approximately 28 GWs.

Some developers are pairing storage with variable, renewable generation, such as solar or wind, to create opportunistic revenue streams. The pairing is either co-located (in which the storage facility and the generator facility are sited on the same parcel of land but each has its own connection to the grid) or hybrid (in which the storage facility and generator share a common connection to the grid).

Capacity Transfers

PJM does not rely on significant transfers to meet resource adequacy requirements. Maximum transfer (total transmission interchange capability) into PJM would amount to less than 2% of PJM's internal generation capability. At no time within this assessment period does the ARM get anywhere near 2%. PJM reliability would not be negatively affected if transfers were dropped to zero.

Transmission

PJM's Regional Transmission Expansion Plan (RTEP) continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by new wind and solar generating units driven by federal and state renewable incentives, generating plant deactivations, and market impacts introduced by DR and EE programs. As of December 31, 2023, renewable resources continue to represent a significant portion of PJM's new services requests.

The PJM board approved 48 new baseline projects during 2023 at an estimated $6.6 billion to ensure that fundamental system reliability criteria across the grid are met. The board also approved the inclusion of 93 new network transmission projects at an estimated $180 million into the RTEP.

Reliability Issues

PJM's 2023 *Load Forecast Report* addressed the impact of industry changes that are reshaping system hourly loads. As a result, the level and timing of coincident peak and non-coincident peak demands across PJM have begun to shift. Solar-power penetration, expected impacts of EVs, state electrification programs, home battery storage, and a significant increase in data center loads are markedly increasing the complexity of PJM's load forecasting process. Driven by discrete and localized load growth, like Data Center Alley in Loudoun County, Virginia, in 2022, PJM and stakeholders conducted a review of data center load growth and identified growth rates of over 300% in some instances. As a result, the 2023 PJM *Load Forecast Report* incorporates adjustments to specific zones for data center load growth.

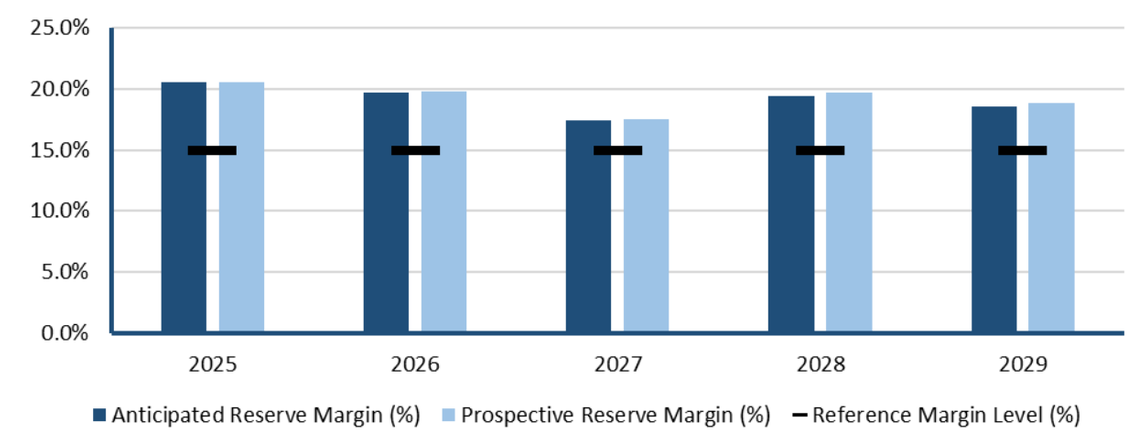


SERC-Central

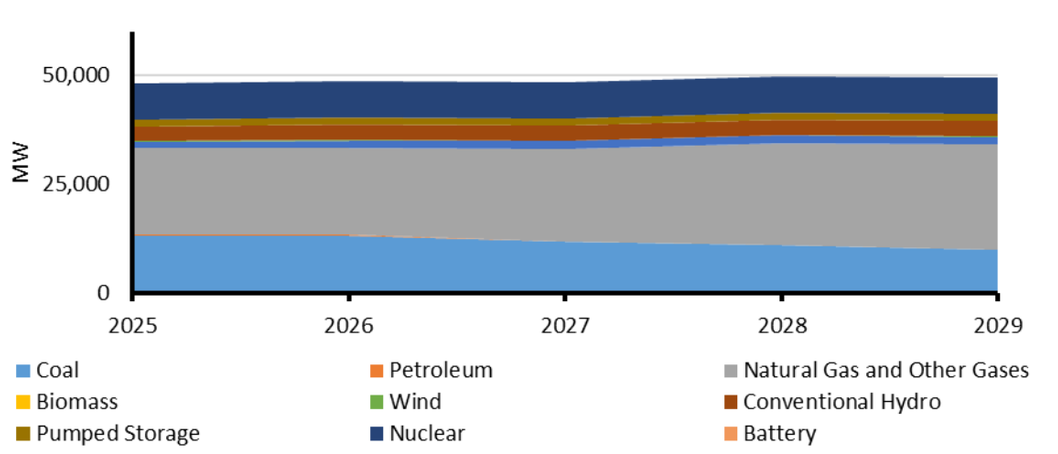
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	42,983	43,202	43,399	43,384	43,440	43,636	43,725	43,913	44,077	44,316
Demand Response	1,859	1,856	1,852	1,849	1,847	1,844	1,842	1,840	1,839	1,837
Net Internal Demand	41,124	41,346	41,547	41,535	41,593	41,792	41,883	42,074	42,239	42,479
Additions: Tier 1	1,123	1,540	2,970	4,983	5,841	5,841	5,841	7,609	8,935	9,598
Additions: Tier 2	20	20	20	120	120	120	120	120	120	120
Additions: Tier 3	135	263	415	1,118	3,395	4,198	4,965	5,368	5,745	6,198
Net Firm Capacity Transfers	1,240	765	190	-288	-288	-288	-288	-287	-287	-287
Existing-Certain and Net Firm Transfers	48,437	47,962	45,813	44,608	43,478	43,191	43,191	42,224	42,224	41,153
Anticipated Reserve Margin (%)	20.5%	19.7%	17.4%	19.4%	18.6%	17.3%	17.1%	18.4%	21.1%	19.5%
Prospective Reserve Margin (%)	20.8%	20.0%	17.7%	19.7%	18.9%	17.6%	17.4%	18.8%	21.4%	19.8%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.
- Projected coal generation retirements total 4,399 MW in the next 10 years. Resource additions include 6,838 MW of natural gas, 75 MW of BESS, and 760 MW of solar generation over the next 10 years.
- New transmission line additions total 209 miles through 2028. The entities also plan to upgrade 185 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows.

SERC-Central Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,348	13,348	11,774	11,047	9,917
Coal*	13,048	13,348	11,146	10,013	8,883
Petroleum	148	148	148	148	148
Natural Gas	19,857	19,857	21,287	23,300	24,158
Natural Gas*	19,476	19,476	20,906	22,919	23,777
Biomass	36	36	36	36	36
Solar	1,338	1,706	1,706	1,706	1,706
Wind	172	172	172	172	172
Conventional Hydro	3,393	3,393	3,393	3,393	3,393
Pumped Storage	1,673	1,673	1,673	1,673	1,673
Nuclear	8,280	8,280	8,280	8,280	8,280
Battery	75	125	125	125	125
Total MW	48,319	48,737	48,593	49,879	49,607
Total MW*	47,639	48,356	47,584	48,464	48,192
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Central Assessment

Planning Reserve Margins
The future reserve margins are above the RML for SERC-Central.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
The 2024 ProbA results shown in the table below indicate negligible unserved energy and load-loss. Analysis of detailed ProbA outputs shows that that this negligible risk occurring in 2026 is associated with hot summer conditions and upper levels of economic load forecast models.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**0.10**	**0.00**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.00**	**0.00**
Operable On-Peak Margin	18.4%	**13.2%**	**14.9%**

* Provides the 2022 ProbA Results for Comparison

Demand
Drivers of load growth are commercial expansion, electrification of heating and transportation, and growth in residential load. Entities expect to continue to have increased economic growth that will drive both population and employment to the SERC-Central assessment area, but these gains in employment are slightly offset by improvements in efficiency.

Distributed Energy Resources
SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation
Projected coal generation retirements total 4,399 MW in the next 10 years. Resource additions include 6,838 MW of natural gas, 75 MW of BESS, and 760 MW of solar generation over the next 10 years.

Generator retirements are carefully managed by entities in the SERC-Central assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Capacity Transfers
Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas within the Region for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission
The entities reported a total addition of 209 miles of new transmission lines until 2028. The entities are also planning to upgrade 185 miles of transmission lines in the next 10 years to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts on reliability.

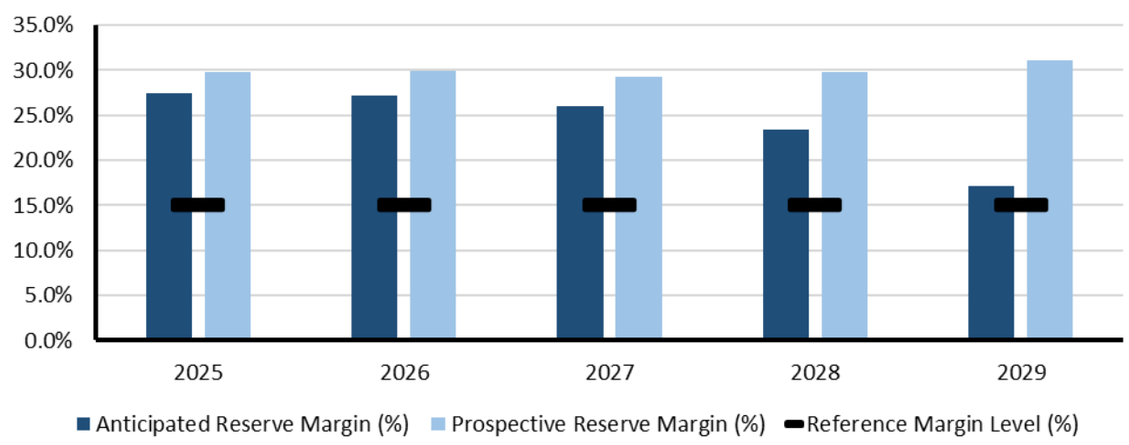


SERC-East

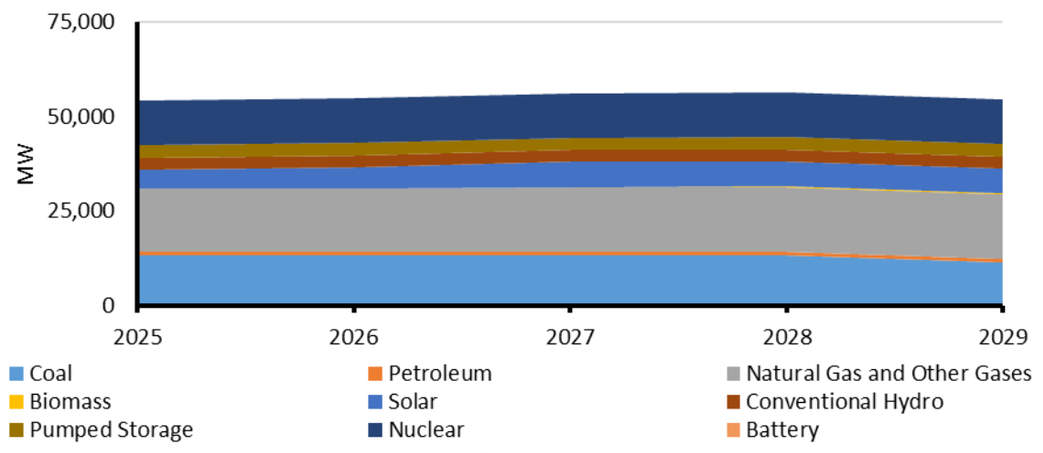
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	44,099	44,789	46,308	47,378	48,286	49,533	50,349	50,896	51,741	52,155
Demand Response	1,092	1,186	1,214	1,225	1,228	1,229	1,230	1,231	1,232	1,233
Net Internal Demand	43,007	43,603	45,094	46,153	47,058	48,304	49,119	49,665	50,509	50,922
Additions: Tier 1	772	1,330	2,777	2,818	2,818	2,818	2,818	2,818	2,818	2,818
Additions: Tier 2	38	217	506	1,975	5,577	8,032	9,766	11,595	13,978	16,767
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	593	593	593	593	593	593	593	593	593	593
Existing-Certain and Net Firm Transfers	54,039	54,129	54,045	54,118	52,301	52,395	51,316	49,998	49,998	48,636
Anticipated Reserve Margin (%)	27.4%	27.2%	26.0%	23.4%	17.1%	14.3%	10.2%	6.3%	4.6%	1.0%
Prospective Reserve Margin (%)	29.8%	30.0%	29.3%	29.8%	31.1%	33.0%	32.1%	31.7%	34.2%	35.9%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the RML until 2030 when it falls below the 15.0% RML level.
- Since the *2023 LTRA*, solar PV resources have grown from 1.5 GW to an expected 4.7 GW by the end of 2024.

SERC-East Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,150	13,150	13,150	13,150	11,333
Coal*	13,108	12,564	12,564	11,910	10,093
Petroleum	1,044	1,044	992	992	992
Petroleum*	1,044	1,044	868	868	868
Natural Gas	16,627	16,717	17,061	17,121	17,121
Natural Gas*	16,601	16,691	17,061	17,121	17,121
Biomass	176	176	176	176	176
Solar	4,995	5,553	6,624	6,665	6,665
Conventional Hydro	3,102	3,102	3,102	3,102	3,102
Pumped Storage	3,324	3,324	3,324	3,324	3,324
Nuclear	11,795	11,795	11,795	11,808	11,808
Battery	6	6	6	6	6
Total MW	54,218	54,866	56,229	56,343	54,526
Total MW*	54,150	54,254	55,519	54,979	53,162
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-East Assessment

Planning Reserve Margins
The ARM falls below the RML starting in 2030 for SERC-East. Projected demand is expected to increase around 8.75% from 2024 to 2028 in the footprint.

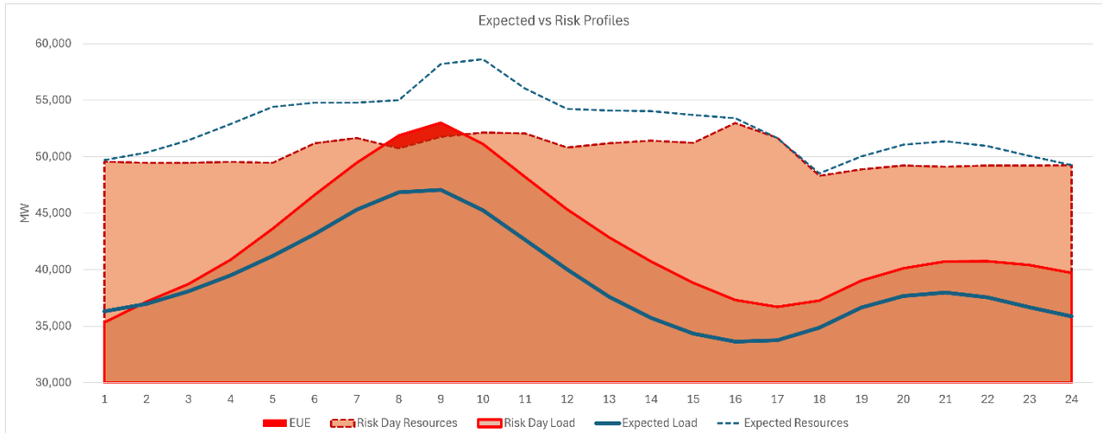
Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
SERC-East has an elevated risk of energy shortages based on results of the 2024 ProbA shown in the table below.

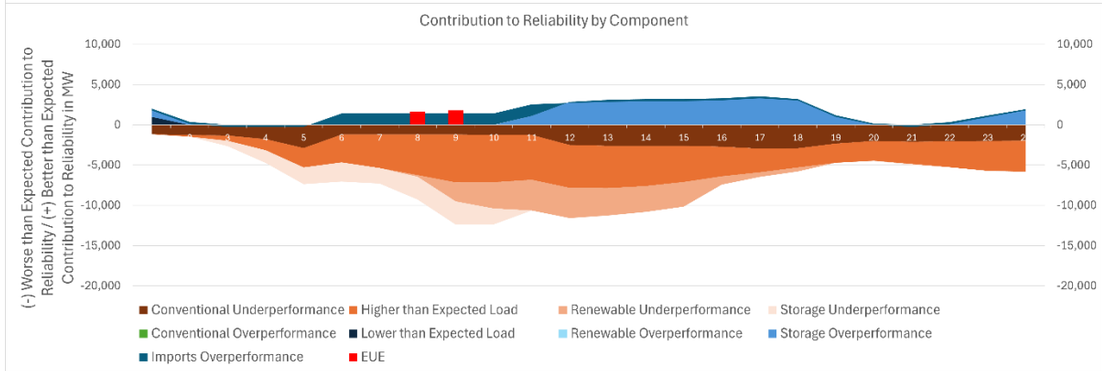
Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	92.49	**143.35**	**207.26**
EUE (PPM)	0.39	**0.60**	**0.81**
LOLH (hours per year)	0.08	**0.09**	**0.17**
Operable On-Peak Margin	16.1%	**14.2%**	**11.1%**

* Provides the 2022 ProbA Results for Comparison

SERC-East has changed from a summer-peaking assessment area to a dual-peaking assessment area, with both a summer and winter peak. The addition of solar PV generation shaves off summer peak demand, and a trend toward electrification of heating drives up winter peak demand. The ProbA results for 2026 indicate some risk for SERC-East in the winter months of January and February. The annual EUE is 143.35 MWh but for a very short, expected duration of 0.09 hours. The risk occurs during winter morning hours around 8:00 a.m. due to a combination of higher loads and solar resources not yet ramped up. For extreme cold weather events that might impact a wide geographical footprint, there is also a limit on imports from neighboring areas.

For 2028, SERC-East continues to show winter risk with 207.26 MWh of EUE and 0.17 hours of LOLH. The load is expected to grow by over 2%. The load-loss events in the analysis are for very few hours and short duration, occur around 8:00 a.m., and are tied to extreme weather, higher forecasted load levels, and lower resource performance. This can be seen in the following figures showing the risk profile and resource performance for a likely event-day.





Demand
Population growth is driving demand forecast increases in SERC-East. Entities expect faster-than-average growth in the urban areas and overall increasing energy and demand in the 10-year forecast. While the economic indicators used in the forecast have growth rates that vary during each year, the economic outlook will contribute to increased energy and demand over the 10-year forecast. Some entities project their EE adoption to impact roughly 1% of annual retail sales (after opt-outs) during the 10-year forecast.

There are also many large commercial/industrial loads accounted for in the forecast that have been announced or in discussions with the entities to locate in the service territory. If the large sites come to fruition, it will drive significant increases in energy and demand during the later part of the 10-year forecast.

The projected EV adoptions are driving energy and demand increases during the later part of the 10-year forecast window. EVs are currently the most significant contributor of all electrification sources (e.g., heating, industrial) in the 10-year forecast.

Distributed Energy Resources

SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

The entities reported a total addition of 286 miles of new transmission lines through 2028. The entities are also planning to upgrade 515 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts on reliability.

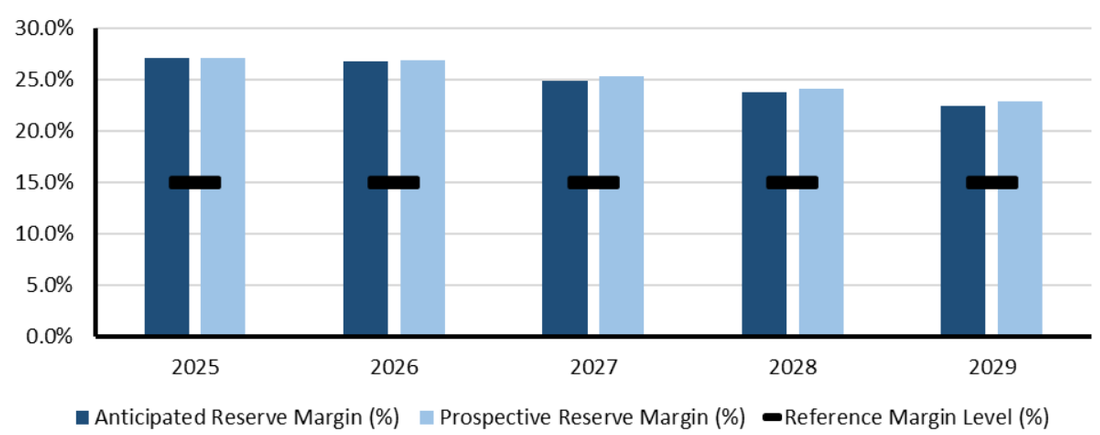


SERC-Florida Peninsula

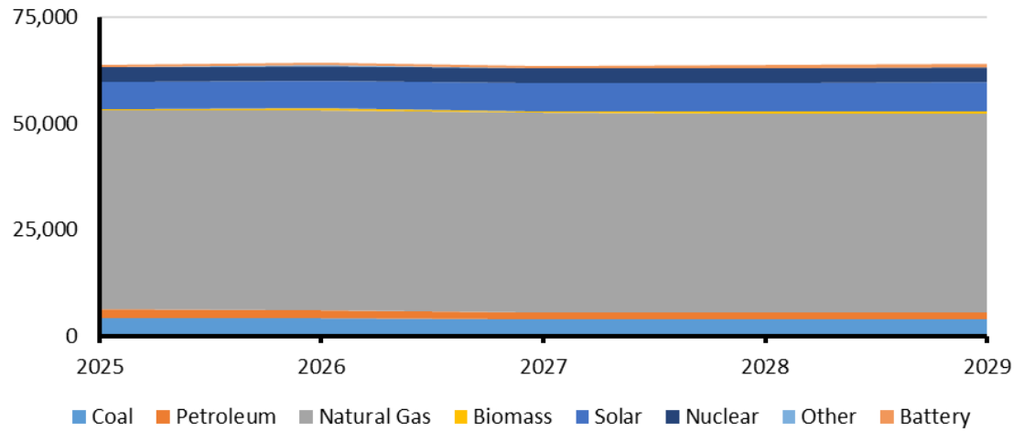
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	53,509	53,795	54,015	54,551	55,250	55,879	56,593	57,612	58,631	59,679
Demand Response	2,840	2,834	2,837	2,820	2,806	2,795	2,783	2,771	2,761	2,748
Net Internal Demand	50,669	50,961	51,178	51,731	52,444	53,084	53,810	54,841	55,870	56,931
Additions: Tier 1	871	1,497	1,573	1,785	2,018	3,421	3,927	4,545	4,547	4,549
Additions: Tier 2	0	40	200	200	200	200	200	200	200	200
Additions: Tier 3	0	39	39	39	39	39	39	39	39	39
Net Firm Capacity Transfers	494	293	293	200	200	200	200	200	200	200
Existing-Certain and Net Firm Transfers	63,521	63,121	62,366	62,230	62,230	61,725	61,725	61,493	61,493	61,493
Anticipated Reserve Margin (%)	27.1%	26.8%	24.9%	23.7%	22.5%	22.7%	22.0%	20.4%	18.2%	16.0%
Prospective Reserve Margin (%)	27.1%	26.9%	25.3%	24.1%	22.9%	23.1%	22.4%	20.8%	18.6%	16.4%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.
- Projected coal generation retirements total 459 MW in the next 10 years. Tier 1 additions include 484 MW of natural gas, 1,560 MW of BESS, and 1,792 MW of solar generation over the next 10 years.
- New transmission line additions total 668 miles through 2030. The entities also plan to upgrade 256 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows.

SERC-Florida Peninsula Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	4,367	4,367	3,908	3,908	3,908
Coal*	3,341	3,779	2,851	2,851	2,851
Petroleum	1,957	1,852	1,724	1,724	1,724
Petroleum*	1,892	1,786	1,477	1,477	1,477
Natural Gas	46,860	47,012	46,844	46,801	46,801
Biomass	310	310	310	310	310
Solar	6,255	6,635	6,711	6,853	6,997
Nuclear	3,502	3,502	3,502	3,502	3,502
Other	9	9	9	9	9
Battery	638	638	638	708	797
Total MW	63,898	64,324	63,646	63,815	64,048
Total MW*	62,807	63,671	62,343	62,512	62,745
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Florida Peninsula Assessment

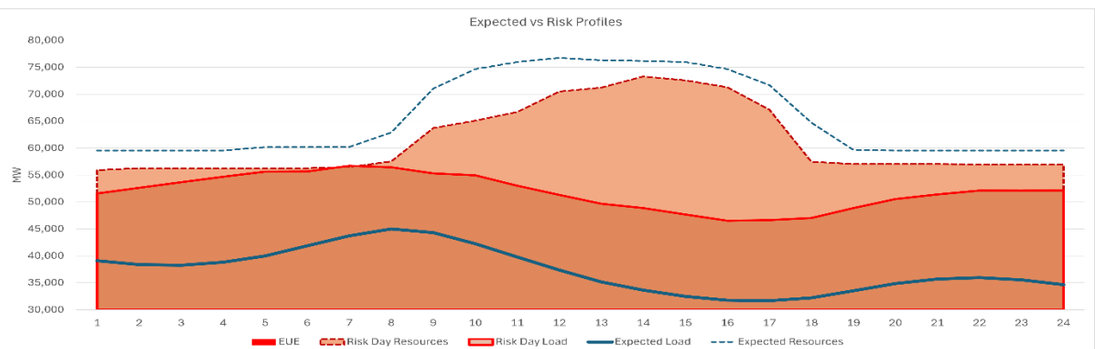
Planning Reserve Margins
The ARM is not expected to fall below the RML for any period of the assessment period.

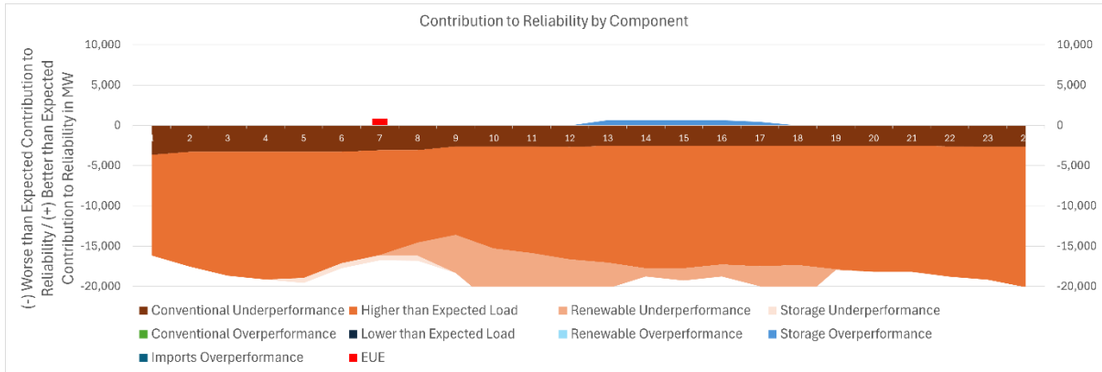
Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
The 2024 ProbA results shown in the table below indicate negligible unserved energy and load loss. Analysis of detailed ProbA outputs shows that that the negligible risk in year 2026 is associated with hot late-summer or early fall conditions, high generator forced outages, and upper levels of economic load forecast models. The risk occurs in evening hours around 7:00 p.m. when contribution from solar generation is limited.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1.13	**2.18**	**16.28**
EUE (PPM)	0.00	**0.01**	**0.06**
LOLH (hours per year)	0.00	**0.01**	**0.02**
Operable On-Peak Margin	18.6%	**19.2%**	**16.3**

* Provides the 2022 ProbA Results for Comparison

For study year 2028, the ProbA results shows very low risk with 16.28 MWh of EUE and 0.02 LOLH hours. The driver of the risk is mainly extreme winter weather, similar to conditions from 1989, when Florida experienced one of the worst winter freezes on record. With higher load levels and lower resources in 2028, the low risk shifts to late December, occurring in morning hours when contribution from solar generation is limited, and is associated with winter freeze events that limit imports.





Demand
The individual entities within the FL-Peninsula Subregion develop their load forecasts and the Florida Reliability Coordinating Council (FRCC) then aggregates these forecasts to calculate a non-coincident seasonal peak for the subregion. Each entity adjusts their forecasts annually to account for their actual peak demands, updated economic outlooks, population growth, weather patterns, conservation and energy efficiency efforts, and electric appliances usage patterns. Based on the data reported in the 2023 FRCC Regional Load and Resource Plan, the net energy for load (NEL) and summer peak demands are forecasted to grow when compared to previous forecasts. The current average annual growth rate for the NEL is 0.97% per year. Firm summer and winter peak demand growth are expected to increase to 1.19% and 1.17%, respectively.

Demand-Side Management
Controllable DR from interruptible and dispatchable load management programs within the FL-Peninsula Subregion is treated as a load-modifier, and it is projected to be constant at approximately 6% of the summer and winter total peak demands for all years of the assessment period.

Distributed Energy Resources
SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation

Generator retirements are carefully managed by entities in the SERC-Florida Peninsula assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Energy Storage

Electricity storage (ES) is still a growing capacity contributor in the assessment area. Over the next 10 years, a total of approximately 2,900 MW of ES generation is projected to be in service by 2032 and is included in the utilities' 10-year site plans (approximately 775 MW by 2029).

Individual entities in the assessment area that have installed or are projecting the installation of ES are developing operating protocols on the use and dispatch of these facilities. ES units are studied as part of the normal generation interconnection process and included in other FRCC studies and processes with members providing individual dispatch profiles and study levels in order to identify potential operational impacts.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

The entities reported a total addition of 668 miles of new transmission lines through 2030. The entities are also planning to upgrade 256 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.

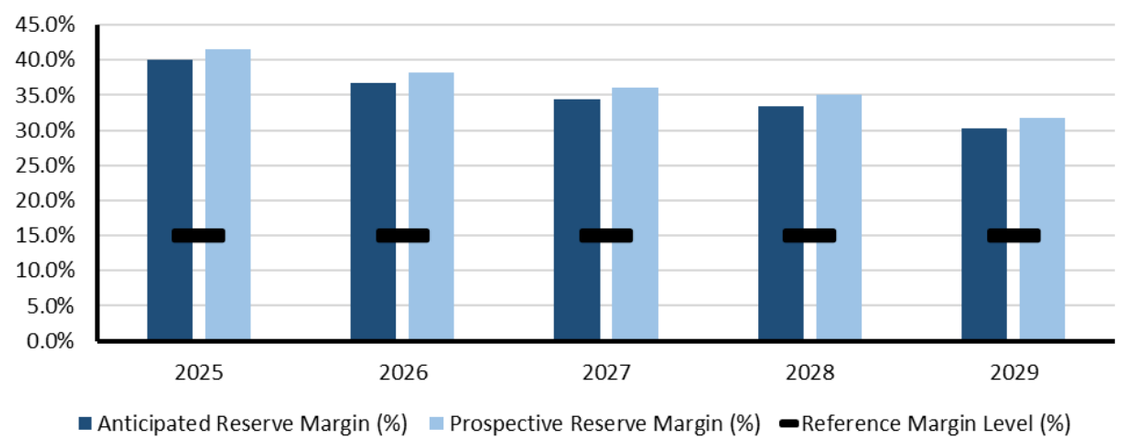


SERC-Southeast

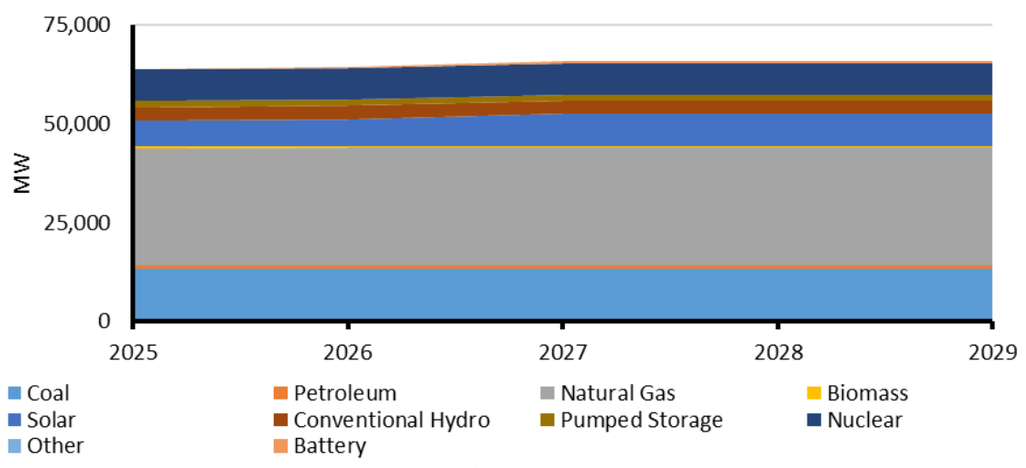
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	46,984	48,384	50,467	50,852	51,974	53,031	53,794	54,233	54,677	55,078
Demand Response	1,633	1,666	1,723	1,755	1,875	1,876	1,875	1,875	1,876	1,876
Net Internal Demand	45,351	46,718	48,744	49,097	50,099	51,155	51,919	52,358	52,801	53,202
Additions: Tier 1	1,248	1,486	3,050	3,050	3,050	3,129	3,129	3,129	3,129	3,129
Additions: Tier 2	105	105	218	218	218	218	218	218	218	218
Additions: Tier 3	366	366	366	366	366	366	366	366	366	366
Net Firm Capacity Transfers	-392	-392	-392	-392	-684	-684	-684	-684	-684	-684
Existing-Certain and Net Firm Transfers	62,257	62,413	62,472	62,472	62,180	62,180	62,180	62,180	62,180	62,180
Anticipated Reserve Margin (%)	40.0%	36.8%	34.4%	33.5%	30.2%	27.7%	25.8%	24.7%	23.7%	22.8%
Prospective Reserve Margin (%)	41.5%	38.2%	36.0%	35.0%	31.7%	29.2%	27.3%	26.2%	25.1%	24.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.

SERC-Southeast Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,275	13,275	13,275	13,275	13,275
Coal*	13,275	13,275	12,271	10,321	10,321
Petroleum	915	915	915	915	915
Petroleum*	915	915	915	899	899
Natural Gas	29,639	29,795	29,854	29,854	29,854
Natural Gas*	29,564	29,387	29,446	28,426	28,426
Biomass	424	424	424	424	424
Solar	6,597	6,835	8,021	8,021	8,021
Conventional Hydro	3,293	3,293	3,293	3,293	3,293
Pumped Storage	1,632	1,632	1,632	1,632	1,632
Nuclear	8,018	8,018	8,018	8,018	8,018
Battery	105	105	483	483	483
Total MW	63,897	64,291	65,914	65,914	65,914
Total MW*	63,822	63,883	64,502	61,516	61,516
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Southeast Assessment

Planning Reserve Margins

The future reserve margins are above the RMLs for SERC-Southeast.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The 2024 ProbA results shown in the table below indicate negligible unserved energy and load loss.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**0.00**	**0.00**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.00**	**0.00**
Operable On-Peak Margin	30.8%	**29.6%**	**25.6%**

* Provides the 2022 ProbA Results for Comparison

Demand

Data centers, cryptocurrency facilities, and large commercial and industrial load are driving demand forecast growth in the assessment area. Metro areas are experiencing a higher growth rate compared to rural areas.

Demand-Side Management

Entities within the SERC-Southeast assessment area use a variety of controllable and dispatchable DR programs to reduce peak demand. One entity manages a voluntary DSM water heater program designed to allow system operators to control the appliances' usage during peak demand periods. Another entity monitors and dispatches DR programs commensurate with contract terms. Annual ELCC simulations are performed to determine the capacity value for each unique and active DR program. An adjustment to that capacity value is then made based on predicted customer response when the program is called or dispatched.

Distributed Energy Resources

SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation

Generator retirements are carefully managed by entities in the SERC-Southeast assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas within the Region for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

The entities reported a total addition of 1,078 miles of new transmission lines in the next 10 years. The entities are also planning to upgrade 694 miles of transmission lines during this time to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.

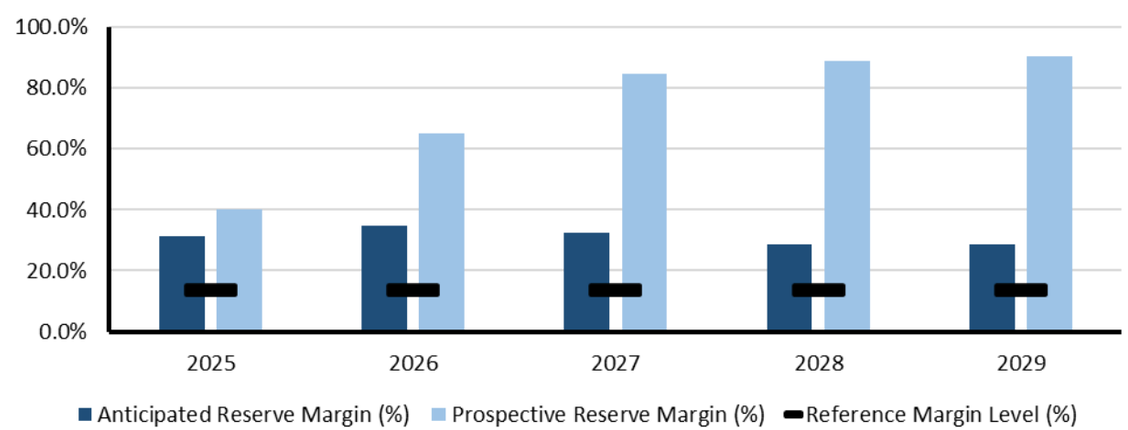


Texas RE-ERCOT

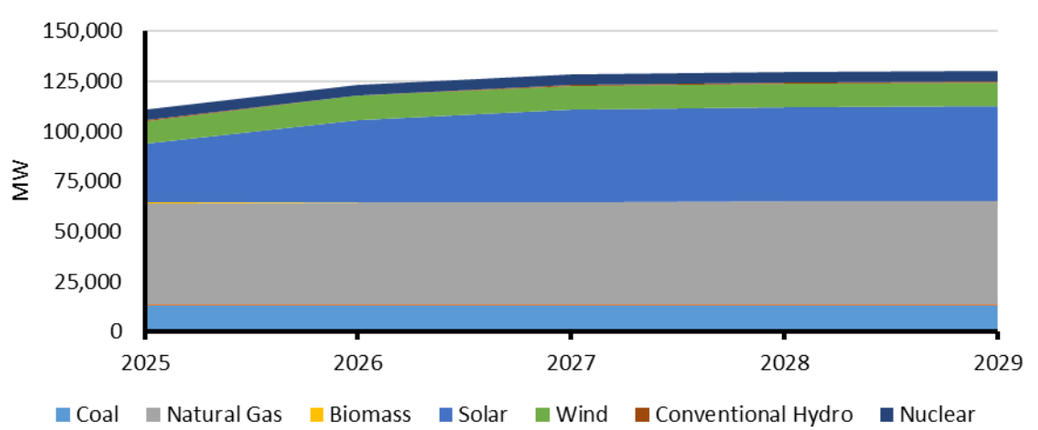
The Electric Reliability Council of Texas (ERCOT) is the ISO for the Texas Interconnection and is located entirely in the state of Texas; it operates as a single BAand performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking and covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million people. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	88,873	95,721	101,405	105,417	106,365	106,951	106,772	106,463	106,062	106,961
Demand Response	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652
Net Internal Demand	86,220	93,069	98,753	102,765	103,713	104,298	104,119	103,811	103,410	104,309
Additions: Tier 1	11,187	23,684	28,725	29,226	29,903	29,903	29,903	29,903	29,903	29,903
Additions: Tier 2	7,281	27,876	51,414	62,225	65,786	65,939	65,939	65,939	65,939	65,939
Additions: Tier 3	7,252	17,627	29,082	41,174	45,318	47,062	47,062	47,062	47,062	47,062
Net Firm Capacity Transfers	20	20	20	20	20	20	20	20	20	20
Existing-Certain and Net Firm Transfers	101,906	101,645	102,003	103,088	103,338	103,338	103,338	103,338	103,338	103,338
Anticipated Reserve Margin (%)	31.2%	34.7%	32.4%	28.8%	28.5%	27.8%	28.0%	28.3%	28.8%	27.7%
Prospective Reserve Margin (%)	40.3%	65.2%	84.6%	88.8%	90.3%	88.8%	89.1%	89.7%	90.4%	88.8%
Reference Margin Level (%)	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Generation resources, primarily solar PV, continue to be added to the grid in Texas in large quantities, increasing ARMs but also elevating concerns of energy risks that result from the variability of these resources and the potential for delays in implementation. The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2025–2034). The ARM peaks at 34.7% by Summer 2026, reflecting the expected addition of about 23,680 MW of Tier 1 capacity, most of which is solar PV.

- The Public Utility Commission of Texas (PUCT) established a reliability standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude. ERCOT will begin performing reliability assessments required by the new standard in 2026.

- ERCOT's summer peak demand is forecast to increase by 4.6% per year from 2025 through 2029. In comparison, the five-year summer peak demand growth projection for the *2023 LTRA* was 1.1%. This high growth level is driven by a large amount of newly contracted loads planned for interconnection during this period. These contracted loads are mainly comprised of Permian Basin oil and gas production facilities, data centers, crypto-mining operations, and industrial facilities.

Texas RE-ERCOT Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	13,568	13,568	13,568	13,568	13,568
Coal*	13,568	13,568	12,913	12,353	12,353
Petroleum	10	10	10	10	10
Natural Gas	50,568	50,694	50,845	51,458	51,458
Natural Gas*	49,709	49,928	48,823	49,436	49,436
Biomass	163	163	163	163	163
Solar	29,557	41,201	45,984	46,485	47,163
Wind	11,332	11,908	12,166	12,166	12,166
Conventional Hydro	458	458	458	458	458
Nuclear	4,973	4,973	4,973	4,973	4,973
Total MW	110,628	122,975	128,167	129,281	129,958
Total MW*	109,769	122,208	125,490	126,044	126,721
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Texas RE-ERCOT Assessment

Planning Reserve Margins

The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2025–2034). The ARM peaks at 34.7% by Summer 2026, reflecting the expected addition of about 23,680 MW of Tier 1 capacity, most of which is solar PV. However, the high reserve margin belies concerns over the continuing trend toward less fully dispatchable resources and more IBRs like solar PV and wind. While thermal resource availability and adequate gas supplies are still concerns during extreme winter weather events, the fleet performed well during Winter Storm Heather in January 2024, indicating that new weatherization standards, fully implemented in 2023, are effective.

Non-Peak Hour Risk and Energy Assurance

The PUCT established a reliability standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude. The latter two measures have an "exceedance tolerance," which is the maximum acceptable percentage frequency of loss-of load events that exceed the permissible thresholds based on a probabilistic simulation.

For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours—peaking at hour ending (HE) 9:00 p.m.—based on probabilistic modeling of monthly peak load days. The elevated risk is due to the drop-off in solar generation and continued higher loads during those hours. The summer peak load hour continues to be 5:00 p.m. For winter, the peak load hour is HE 8:00 a.m. Risk modeling indicates elevated reserve scarcity risk for the morning hours (HE 7:00 a.m. to 9:00 a.m.) as well as the early evening hours.

ERCOT is experiencing transmission limitations as a result of load growth and resource development that affect energy delivery. On March 1, 2024, ERCOT introduced four new Interconnection reliability operating limits (IROL) in the South Texas region. This consists of two South Texas import constraints and two South Texas export constraints, which, if violated, could result in a thermal cascading condition. This is the first thermal IROL that could lead to a cascading condition in the Texas RE-ERCOT Region and has been attributed to the increase in generation capacity in South Texas and the rapid load growth in central Texas. To manage the South Texas export constraint, generation in South Texas must be curtailed to maintain transmission line flows below 100% of the impacted lines' thermal ratings. The risk of such curtailments, which is highest for the hours with the highest net peak loads (early evening), is included in the monthly probabilistic reserve risk assessments. ERCOT has approved two San Antonio Reliability projects that are expected to be completed in 2027 and should help alleviate some of risk drivers associated with these IROLs.

Probabilistic Assessment

Results of the 2024 ProbA are shown in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1,235	**11,090**	**781**
EUE (PPM)	2.63	**18.95**	**1.12**
LOLH (hours per year)	0.30	**1.57**	**0.16**
Operable On-Peak Margin	35.9%	**28.8%**	**46.9%**

* Provides the 2022 ProbA Results for Comparison

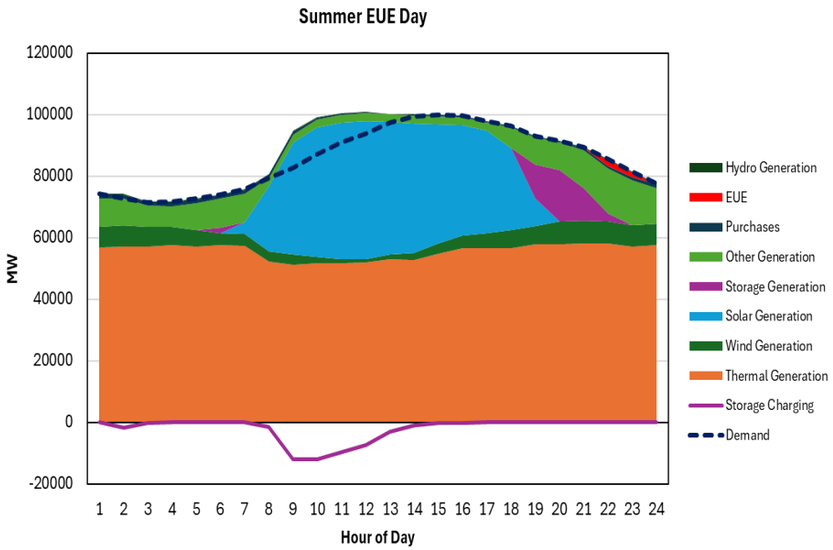
Increasing reliability risk in ERCOT is primarily driven by increasing large load demand anticipated from data centers, Bitcoin operations, continued load growth in oil and gas-producing areas (such as the Permian Basin), and growth in industrial facilities. Over 20 GW of newly contracted large loads, in addition to other organic load growth, is projected to be added to ERCOT by 2028. ERCOT also anticipates 1,860 MW of fossil-fueled plant capacity to be retired by Summer 2028. New planned units are primarily renewable and storage, which exhibit declining marginal reliability contributions. The reliability forecasts provided by this ProbA assessment for 2028 include resource capacity contributions from expansion planning analysis conducted for ERCOT's 2024 *Long-Term System Assessment*. While there is uncertainty around the deployment of these resources, the large load demand growth is also uncertain and large loads are subject to various requirements for being integrated into the grid.

All SERVM simulations for ERCOT and surrounding regions impose all relevant generator temporal constraints, including operating limitations on conventional units as well as state-of-charge on batteries, so this assessment accounts for energy adequacy. However, this assessment does assume fuel for conventional units will be available when needed.[37]

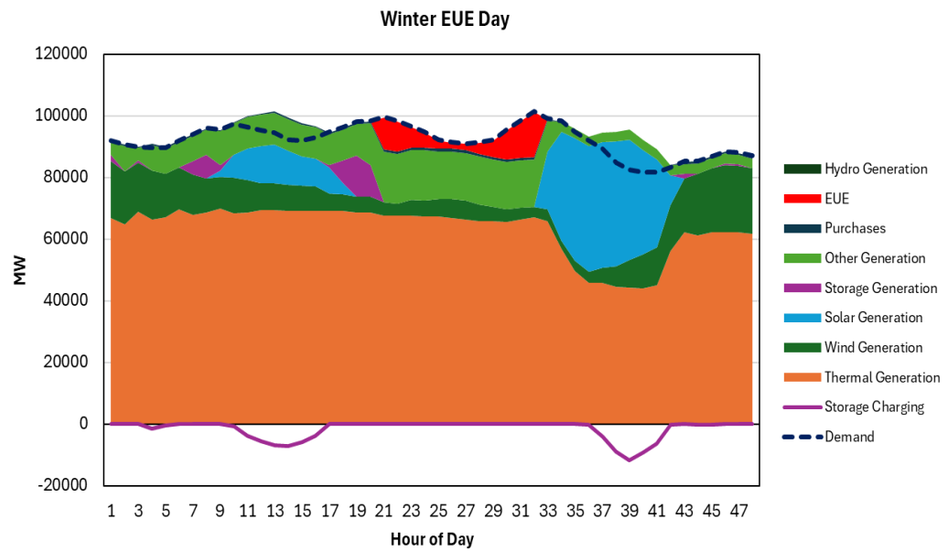
The unique characteristics of winter risk vs. summer risk can be seen in the following charts of a representative risk day. While peak winter loads can persist for 48 hours or longer, peak summer

[37] ERCOT and several other entities used SERVM software tool to perform the ProbA. Information about SERVM can be found at the company's website.

periods generally only last for a few hours. This has significant implications for the duration and depth of firm load-shed events in the winter as well as for the reliability contribution of energy limited and non-dispatchable resources. The most extreme winter event modeled for 2026 was 16 hours in duration and 29 GW in depth. The illustration below indicates a winter EUE event with duration >12 hours while most summer events were 1–2 hours in duration.



Metric	2026 Summer	2026 Winter	2028 Summer	2028 Winter
LOLE (days/year)	0.38	0.51	0.05	0.04
LOLH (hours/year)	1.41	1.57	0.18	0.16
EUE (MWh)	10,985	11,090	857	781
Max Hourly EUE (MWh)	29,124	29,266	17,762	16,851
Max EUE Duration (Hr)	15	16	12	11



From the hourly event data, ERCOT provided a multi-metric summary of the largest event showing the highest magnitude and longest-duration, as shown in the following figure.

Demand

ERCOT's long-term load forecast consists of the following individual components: (1) a base forecast that uses an econometric model with estimation data comprising 15 historical weather years, economic drivers, calendar information, and historical loads, (2) a roof-top PV forecast, (3) an EV forecast, a large flexible load forecast (crypto-mining facilities), and new "large loads" with a signed interconnection contract with their transmission or distribution service provider. Forecasts are provided for eight weather zones as well as system coincidental and non-coincidental demands. ERCOT's summer peak demand is forecast to increase by 4.6% per year from 2025 through 2029. In

comparison, the five-year summer peak demand growth projection for the *2023 LTRA* was 1.1%. This high growth level is driven by a large amount of newly contracted loads planned for interconnection during this period. These contracted loads are mainly comprised of Permian Basin oil and gas production facilities, data centers, crypto-mining operations, and industrial facilities. (A negligible amount of new contracted loads reported by transmission service providers occur past 2029). The base peak load, which excludes these new contracted loads as well as load reductions due to rooftop solar installations, grows at a more modest 1.4%.

A major load forecasting change from last year is a new Texas Legislature requirement to include non-contracted loads in transmission planning studies. Non-contracted loads lack a signed Interconnection or facility expansion agreement. ERCOT's previous practice had been to exclude these more speculative loads from the load forecast. The non-contracted loads total about 3.6 GW for summer 2025 and reach about 31.7 GW by 2029. The non-contracted loads are not included in the LTRA's peak load forecast. ERCOT is evaluating how these non-contracted forecasted loads will be handled for future resource adequacy and other planning activities.

Demand-Side Management

Most of the demand-side resources available to ERCOT are dispatchable in the form of noncontrollable load resources providing responsive reserve service and ERCOT's Emergency Response Service. The ERCOT Emergency Response Service consists of 10- and 30-minute ramping DRs and distributed generation that can first be deployed when physical responsive reserves drop to 3,000 MW and are not projected to be recovered above 3,000 MW within 30 minutes following the deployment of non-spin reserves. Responsive reserve is provided by industrial loads and is procured on an hourly basis in the day-ahead market. During 2023, load resources started to participate in two other ancillary services, the Non-Spinning Reserve Service and ERCOT Contingency Reserve Service (ECRS), which are used to help balance the system during periods when there may be net-load ramps that cannot be met with conventional supply-side resources.

The remaining dispatchable DR available to ERCOT is from the transmission and distribution service providers' (TDSP) load management programs. These programs provide price incentives for voluntary load reductions from commercial, industrial, and residential loads during energy emergency alert events.

Distributed Energy Resources

DERs that register with ERCOT to participate in wholesale energy and/or ancillary services markets are modeled and dispatched in ERCOT transmission planning studies similarly to transmission-connected resources participating in those markets. For DERs not participating in those markets, ERCOT relies on member TDSPs to provide information about individual DERs on their systems for shorter-term reliability and economic impact studies, typically a one-to-six-year timeframe.

A bill was approved in the 88th Texas Legislature (HB 3390) that outlines new DER reporting responsibilities. The bill authorizes ERCOT to require TDSPs to provide unregistered DER information that ERCOT deems necessary for grid reliability assessment. ERCOT is now developing annual data collection and maintenance processes.

A multi-phase aggregated DER (ADER) pilot program was implemented in 2022. As of May 2024, there were two ADERs with 13 MW of dispatchable capability actively participating in the pilot project with another nine ADERs in various stages of registration/qualification.

Generation

Natural-gas-fired generation makes up approximately 45% of the available generation inside the ERCOT footprint. Approximately 6% of the natural-gas-fired generation demonstrates firm fuel capabilities as part of ERCOT's Firm Fuel Supply Service required by the PUCT.

ERCOT has established formal working relationships with grid generators' fuel suppliers to gather operational and delivery information useful for its control room operators. ERCOT has focused the efforts on two fronts: (1) obtaining real-time (or near real-time) information on the health of the natural gas systems that serve the generators and (2) maintaining communication with pipelines to notify ERCOT of any planned or unplanned events that could impact deliveries to generators.

After the 2021 Odessa event, ERCOT intensified its efforts to find corrective measures to enhance the ride-through performance of IBRs and improve overall system resilience. The study, which recommended installing synchronous condensers at six locations in West Texas, has been completed, and the ERCOT board of directors endorsed the project in December 2023. The project is expected to be in service in 2027.

ERCOT has proposed new grid code requirements for IBRs to improve voltage ride-through (VRT) performance to align with IEEE Standard 2800. The proposed grid code requirements are continuing to go through ERCOT's stakeholder approval process. Until new rules go into effect, IBRs will be expected to maximize VRT capability and address existing performance failures (such as by reducing maximum output).

To provide an incentive to build new dispatchable resources, the PUCT adopted a new rule to establish a generation loan program, one of four incentive programs under the recently established Texas Energy Fund (TEF). The other three programs within the TEF include completion bonus grants for new dispatchable generation projects that consistently provide power generation over a 10-year period, grants for companies to establish or secure backup power resources, and grants to improve the resiliency and availability of electric utility service outside the ERCOT region. The TEF has $5 billion

available for all four programs. These loans and grants have thus far resulted in 72 applications seeking funding under the TEF loan program. The PUCT staff-recommended portfolio represents 9,781 MW in potential new generation if all recommended applicants were to execute a loan agreement at the requested loan amounts.

Energy Storage

The current installed BESS capacity is 9,149 MW. These systems participate in ERCOT's Energy and Ancillary Service markets. Most have durations in the one-to-two-hour range. ERCOT is seeing an increase in longer-duration systems (three to four hours) to take advantage of energy-shifting and capacity-firming opportunities arising from continued high renewable generation penetration. For the first half of 2024, energy storage provided 87% of ERCOT's regulation up and 91% of responsive reserve service from primary frequency response (RRS-PFR). In June 2023, ERCOT implemented a new ancillary service, the ERCOT Contingency Reserve Service (ECRS), which, in part, is designed to address the ramping needs of the system. This ancillary service product provides additional opportunities for BESS ancillary service participation. To support larger BESS penetration levels, ERCOT submitted new proposed rules for state-of-charge accounting in energy dispatch and reliability unit commitment that are planned for implementation this year.

Based on the latest developer information for projects that are in the interconnection queue, ERCOT expects about 10,500 MW of additional battery energy storage capacity to be operational by year-end 2025. This capacity constitutes projects for which developers have posted financial security to build the interconnection facilities. By year-end 2029, the additional cumulative Tier 1 planned capacity reaches about 20,000 MW.

ERCOT currently assigns a 0% on-peak contribution for battery energy storage. ERCOT has changed its rule to adopt an ELCC methodology for battery storage of various durations. Extending the proposed ELCC methodology for BESS to current and forecasted resources in ERCOT would improve the anticipated reserve margins in the future.

Capacity Transfers

ERCOT has coordination plans in place with neighboring grids. These plans cover dc tie emergency operations, procedures for generators that can switch between grids, and temporary block load transfers.

Transmission

In September, the PUCT approved ERCOT's Permian Basin Reliability Plan. The plan consists of new and upgraded local transmission projects as well as building new import paths to load centers in other areas of the Texas RE-ERCOT region, including options for extra high voltage (EHV) infrastructure operating at 345 kW or 765 kV. The plan supports Permian Basin load growth that is currently expected to reach 24 GW by 2030 and over 26 GW by 2038.

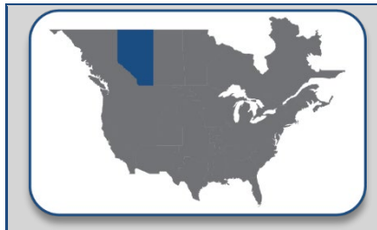
ERCOT's 2023 Regional Transmission Plan (RTP) identified 173 reliability projects, with the majority consisting of 138 kV and 345 kV system upgrades. The 2023 RTP also included an economic assessment of the ERCOT transmission system for years 2025 and 2028 using production cost savings and generator revenue reduction tests.

The substantial increase in new loads from a year ago is expected to present challenges for transmission planning. The forecasted pace of the load growth could exceed the pace at which transmission capacity can be built to support it. ERCOT is working on major changes to its transmission planning process to address these challenges. For example, ERCOT is investigating a "generation hub" concept to indicate optimal generation location to address regional load growth and optimize transmission investments.

A new biennial report on grid resiliency—the Grid Reliability and Resiliency Assessment—evaluates extreme weather scenarios considering different levels of thermal and renewable generation availability and the potential outages caused by extreme weather conditions. The assessment also includes proposed transmission projects that may mitigate regional resiliency risks. The first report will be released by December 31, 2024.

New minimum deliverability criteria were included in ERCOT's 2023 RTP to ensure the deliverability of 100% of generation resource capacity and energy storage resources with a duration greater than or equal to two hours. For storage systems with a duration less than two hours, a prorated deliverability was ensured. Corrective action plans (CAP) were proposed to address any reliability violations under the contingencies defined for the minimum deliverability criteria.

ERCOT has also started implementing the PUCT's amended rules relating to certification criteria and is in the process of integrating a new congestion cost savings test for economic projects evaluation.

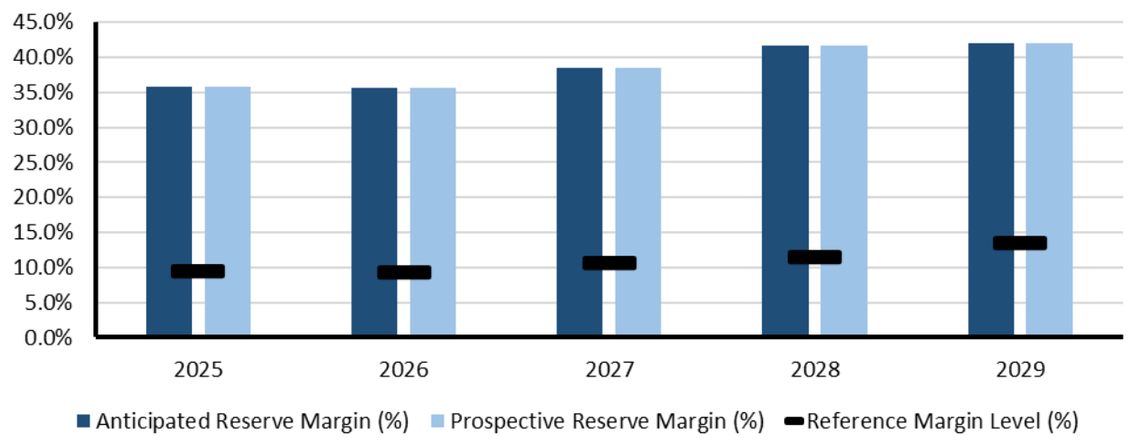


WECC-AB

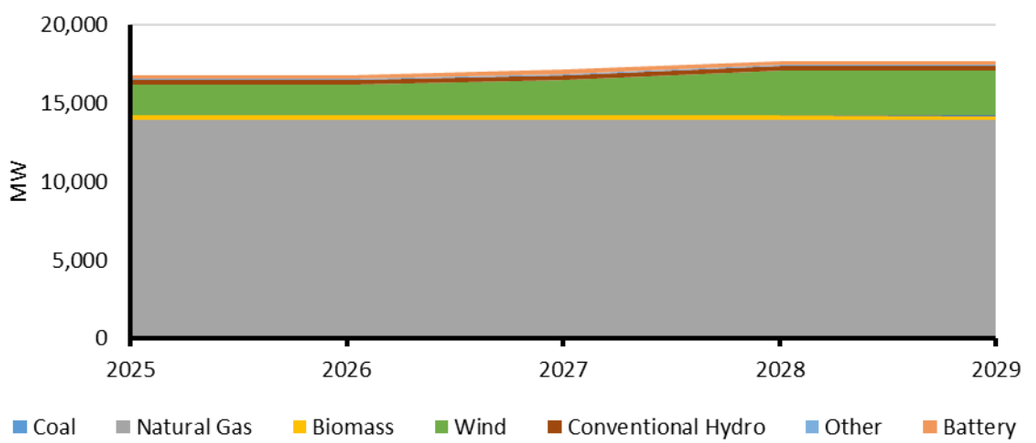
WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and BC in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	12,411	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,411	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076
Additions: Tier 1	3,275	3,275	3,405	3,541	3,537	3,342	3,537	3,441	3,273	3,273
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	1,031	1,680	1,824	2,247	2,700	2,502	3,068	3,096	2,744	2,744
Net Firm Capacity Transfers	43	96	69	0	68	396	409	0	0	0
Existing-Certain and Net Firm Transfers	13,578	13,631	13,822	14,182	14,244	13,931	14,585	13,867	13,330	13,330
Anticipated Reserve Margin (%)	35.8%	35.6%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
Prospective Reserve Margin (%)	35.8%	35.6%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
Reference Margin Level (%)	9.4%	9.4%	10.6%	11.5%	13.6%	9.2%	13.2%	11.3%	9.0%	9.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML during the 2024–2034 timeframe.
- The peak hour of demand for Alberta occurs in the winter. The peak hour for total internal demand is expected to grow from about 12.3 GW in 2024 to 13.1 GW in 2034, a 6.5% load growth over the forecast horizon. The average year-to-year growth rate is 0.62%. There is a slight increase in the load forecast for this year's LTRA versus last year's.
- Despite low resource adequacy risk, operational risk is still present. Ensuring sufficient frequency response capability has been identified as the region's highest priority. Frequency response has been declining in the region due to the increasing share of IBR resources and declining baseload resources. This under frequency load shedding risk is exacerbated in islanded or near-islanded situations.
- Alberta's two remaining coal-fired generators completed their conversion to natural gas this year.

WECC-AB Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Natural Gas	13,932	13,932	13,941	13,930	13,920
Biomass	336	336	336	336	336
Wind	1,912	1,912	2,232	2,811	2,799
Conventional Hydro	285	285	303	302	312
Other	81	81	81	81	81
Battery	264	264	264	264	263
Total MW	16,810	16,810	17,157	17,723	17,713

WECC-AB Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2024–2034 timeframe. From the 2032–2033 winter onward, Alberta shows a shortfall of existing-certain and net firm transfers. This indicates that imports may be necessary during this timeframe if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the one-day-in-ten-year (ODITY) level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

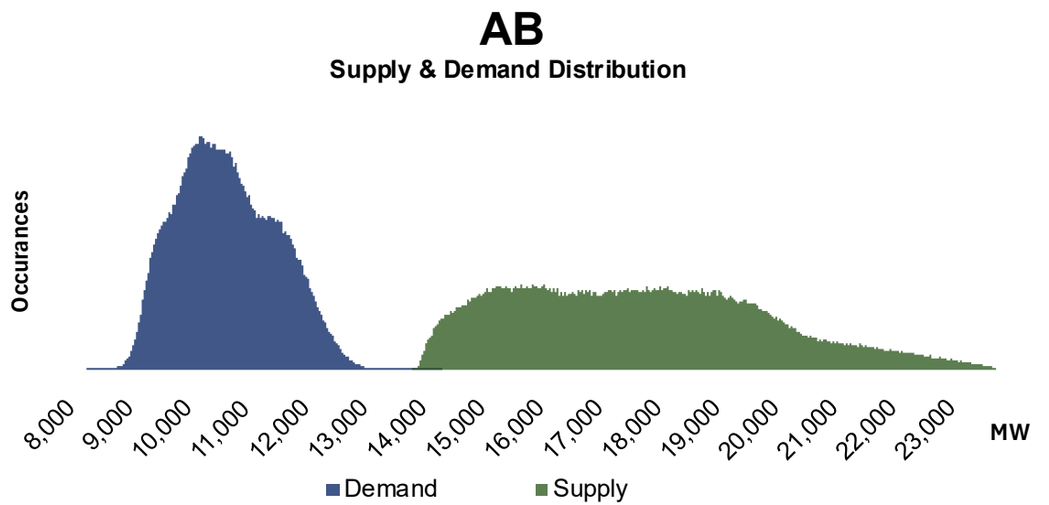
Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0	0	0
EUE (PPM)	0	0	0
LOLH (hours per year)	0	0	0
Operable On-Peak Margin	26.1%	41.6%	42.4%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the Multi-Area Variable Resource Integration Convolution (MAVRIC) model. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment. WECC also produces an annual reliability assessment called the *Western Assessment of Resource Adequacy* (WARA).[38]

The availability and demand distributions in the ProbA simulations do not overlap, indicating an extremely low probability of Alberta not being resource adequate over the next four years. For 2026 and 2028, the peak hour occurs in December at HE 18:00. Alberta does not show LOLH nor EUE in the LTRA forecast horizon. The gap between the demand distribution and the supply distribution shown in the figure below emphasizes that there is minimal resource adequacy risk in Alberta. The ARM appears to further validate this, as it is far above the RML for 2026 and 2028.



Demand

Peak demand for Alberta occurs in the winter. The peak hour for total internal demand is expected to grow from about 12.3 GW in 2024 to 13.1 GW in 2034, a 6.5% load growth over the forecast horizon. The average year-to-year growth rate is 0.62%. There is a slight increase in the load forecast for this year's LTRA versus last year's. Near-term load growth is driven by industrial loads, such as oil sands production, pulp and paper mills, and gas and oil processing. Long-term demand growth is driven by electrification of transportation and buildings as well as potential growth in emerging industries, such as hydrogen production.

[38] See WECC Reliability Assessments.

Distributed Energy Resources
BTM DERs are difficult to measure due to data gathering barriers. AESO released its updated 2022 Plan for DER Roadmap Integration Activities.

Generation
Over 6 GW of nameplate capacity are being added in Alberta through the end of 2028. There is significantly more solar, wind, and energy storage in this year's planned capacity additions than in the last LTRA. Additionally, several states and provinces in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions. Alberta's two remaining coal units have been converted to natural gas this year.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
In WECC's analysis, Alberta is not showing significant changes to capacity transfers. There is a slight increase in exports between 5:00 p.m. and 10:00 p.m. and in the later years of the assessment period.

Reliability Issues
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

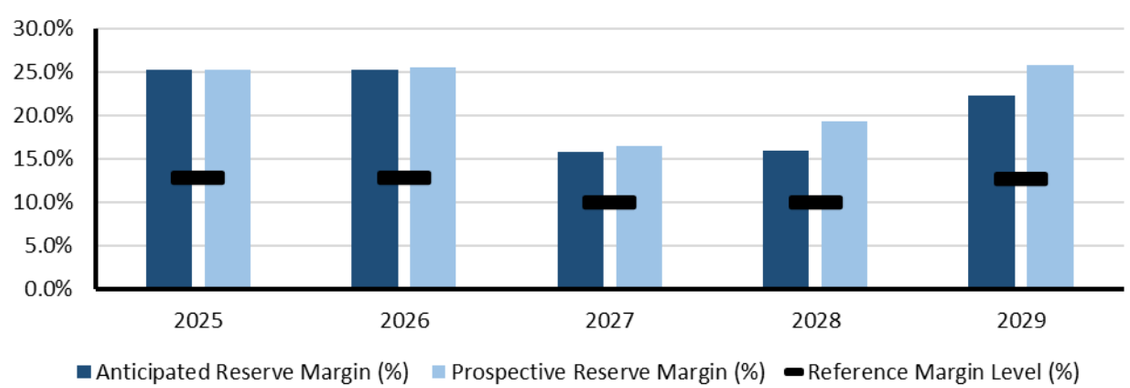


WECC-BC

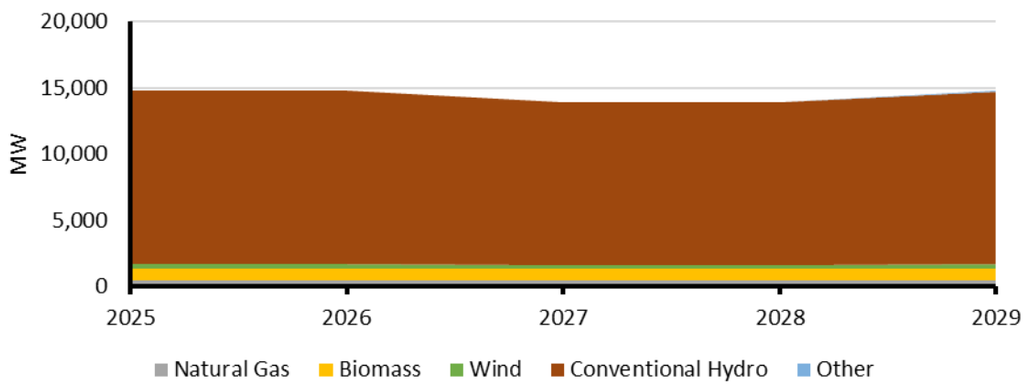
WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of BC, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and BC in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	11,986	11,959	12,015	11,983	12,075	12,082	12,130	12,174	12,237	12,305
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,986	11,959	12,015	11,983	12,075	12,082	12,130	12,174	12,237	12,305
Additions: Tier 1	956	956	893	893	956	956	956	956	893	956
Additions: Tier 2	0	41	79	398	419	748	1,077	1,077	1,012	1,405
Additions: Tier 3	0	5	5	5	6	6	59	59	56	59
Net Firm Capacity Transfers	184	188	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	14,054	14,022	13,019	12,998	13,812	13,795	13,795	13,795	12,982	13,795
Anticipated Reserve Margin (%)	25.2%	25.2%	15.8%	15.9%	22.3%	22.1%	21.6%	21.2%	13.4%	19.9%
Prospective Reserve Margin (%)	25.2%	25.6%	16.5%	19.2%	25.8%	28.3%	30.5%	30.0%	21.7%	31.3%
Reference Margin Level (%)	12.8%	12.8%	10.0%	10.0%	12.7%	12.7%	12.6%	12.6%	9.8%	12.5%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML during the 2024–2034 timeframe.
- BC shows a shortfall of existing-certain and net firm transfers for the 2027–2028 winter and the 2028–2029 winter. Shortfalls are also projected from the winter of 2033–2034 onward. This indicates that imports may be necessary during these periods if new resources were to be significantly delayed.
- The peak hour of demand for BC occurs in the winter. BC shows the lowest demand growth rate in the west. The peak demand is expected to grow from about 12.0 GW in 2024 to 12.3 GW in 2034, slightly less than in the previous LTRA forecast. This is an average annual growth rate of 0.28%, and a 2.8% load growth over the forecast horizon.
- BC is showing hours of demand at risk that are not fully mitigated by the addition of Tier 3 resources. Supply chain performance will play a significant role in BC's ability to reliably meet energy needs. Seasonal and daily fluctuations of hydro resource availability is also a risk. LOLH and EUE correlate with periods when river flows are at their lowest.

WECC-BC Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Natural Gas	459	459	456	456	459
Biomass	920	920	914	914	920
Wind	279	279	268	268	279
Conventional Hydro	13,145	13,110	12,253	12,232	13,087
Other	22	22	22	22	22
Total MW	14,825	14,790	13,912	13,891	14,768

WECC-BC Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2024–2034 timeframe. BC shows a shortfall of existing-certain and net firm transfers for the 2027–2028 winter and the 2028–2029 winter. Shortfalls are also projected from winter of 2033–2034 onward. This indicates that imports may be necessary during these periods if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk in 2026. In 2028, however, WECC's analysis identified over five hours where resources, including imports from neighbors, fall below margins for system reliability.

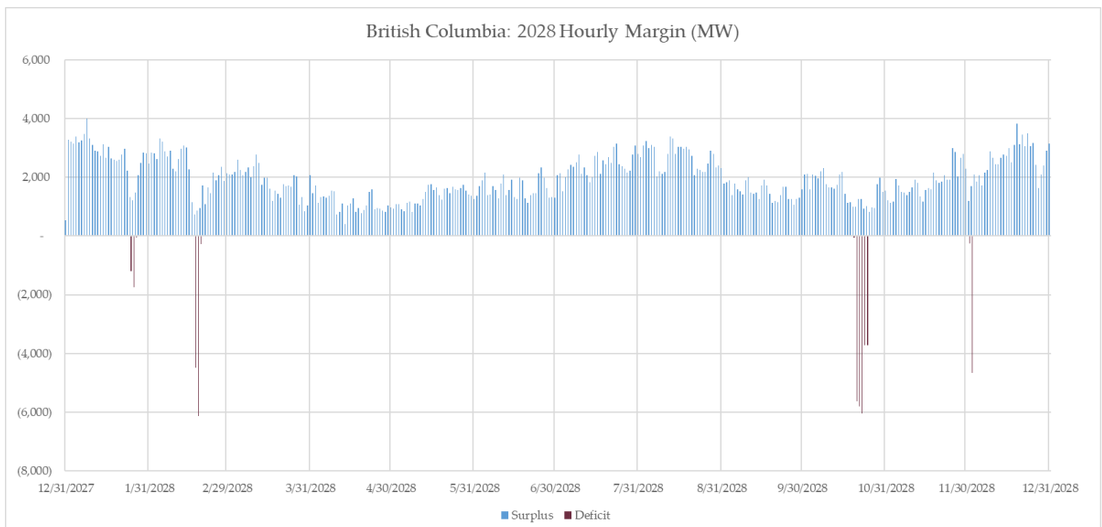
Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	24	0	103,132
EUE (PPM)	0.71	0	1,457
LOLH (hours per year)	0.002	0	5.52
Operable On-Peak Margin	12.7%	16.9%	9.4%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

For both 2026 and 2028, the peak hour occurs in December at HE 19:00. LOLH and EUE are not forecast in 2026 but do appear in 2028. No LOLH or EUE occurs at the peak hour. 88% of the EUE in 2028 occurs overnight between the hours of 23:00 and 4:00.

In 2026, the peak summer hour is HE 17:00 in September, and in 2028 the peak hour is HE 17:00 in August. There is no LOLH projected for 2026 or during peak hours. LOLH occurs in 2028 between the hours of 17:00 and 20:00.



Icicle Plot with Hourly Surplus and Deficits for British Columbia in 2028

WECC's interconnection-wide analysis simulates the probabilistic performance of resource types using historic hourly output data to identify future risk periods. Operators of systems with large hydroelectric storage facilities make adjustments to generation based on the level of demand and shape the water use within the day, week, month, or between years. These actions help posture hydroelectric generation for expected conditions and can reduce energy shortfall risks.

	1	2	3	4	5	6	7	8	9	10	11	12
0	(0)	(5)	-	-	-	-	-	-	-	(10)	-	-
1	(1)	(5)	-	-	-	-	-	-	-	(12)	-	-
2	(1)	(6)	-	-	-	-	-	-	-	(20)	-	-
3	(3)	(5)	-	-	-	-	-	-	-	(14)	(0)	-
4	(0)	(1)	-	-	-	-	-	-	-	(0)	(0)	-
5	-	(0)	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	(0)	-	-
8	-	(0)	-	-	-	-	-	-	-	(0)	-	(0)
9	(0)	(0)	-	-	-	-	-	-	-	-	-	(0)
10	-	(0)	-	-	-	-	-	-	-	-	-	(0)
11	-	-	-	-	-	-	-	-	-	-	-	(1)
12	-	-	-	-	-	-	-	-	-	-	-	(3)
13	-	(0)	-	-	-	-	-	-	-	-	-	(5)
14	-	-	-	-	-	-	-	-	-	-	-	(1)
15	-	(0)	-	-	-	-	-	-	-	-	-	(0)
16	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-	-	-	-	-
20	-	(0)	-	-	-	-	-	-	-	-	-	-
21	-	(0)	-	-	-	-	-	-	-	-	-	-
22	-	(0)	-	-	-	-	-	-	-	(0)	-	(0)
23	-	(2)	-	-	-	-	-	-	-	(5)	-	-

2028 Heat Map EUE (GW) - British Columbia

Demand

BC's average annual load growth in its forecast has fallen to a rate below Alberta's. The peak hour total internal demand for BC occurs in the winter. The peak demand is expected to grow from about 12.0 GW in 2024 to 12.3 GW in 2034, slightly less than in the last forecast. This is an average annual growth rate of 0.28% and a 2.8% load growth over the forecast horizon. BC's load growth is lower due to updated monthly profiles that reflect current trends and aggressive DSM which it includes as a demand reduction in the demand forecasts provided to WECC. Load growth in BC is primarily driven by EV and gas sector load growth and is partially offset by a decline in demand from the forestry sector.

Distributed Energy Resources

BTM DERs are difficult to measure due to data-gathering barriers. BC Hydro has net metering. Net metering for residential and commercial customer projects are up to 100 kW. The net metering program has no annual energy volume target.

Generation

Across WECC, several states and provinces as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

In BC, hydro and wind resources are being added to the system. The BC Hydro Authority (BCHA) is taking steps to mitigate risks associated with climate change by improving coastal watershed inflow forecasting to an hourly level and increasing investment in capital projects to increase the resiliency of its hydro-dominant portfolio. Drought conditions in BC have led to water conservation measures, such as encouraging generation at facilities located in less drought-impacted areas, revising discharge plans at storage capable sites, and importing power when available to reduce water consumption.

Capacity Transfers

WECC's probabilistic analysis indicates that BC's need for imports is increasing during the assessment period.

Transmission

Three transmission projects with voltage design of 500 kV and higher are planned in the BC region.

Reliability Issues

WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

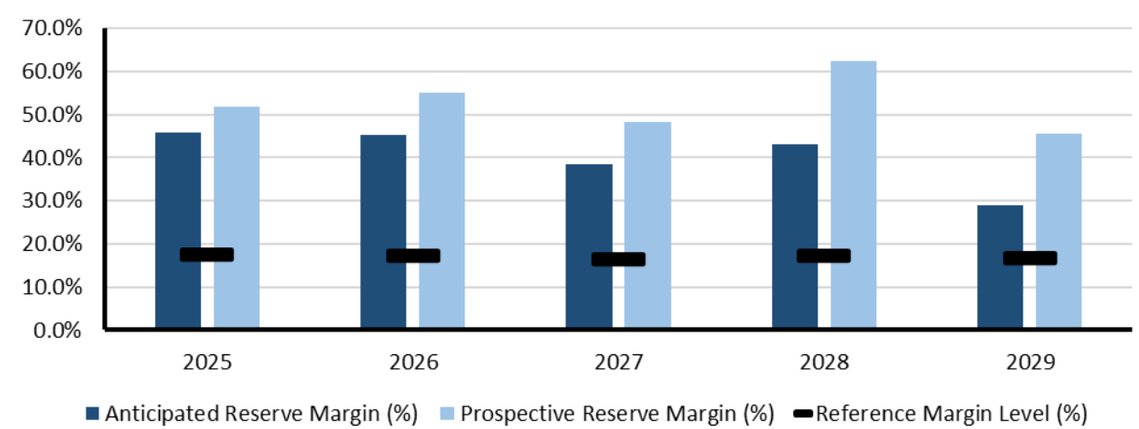


WECC-CA/MX

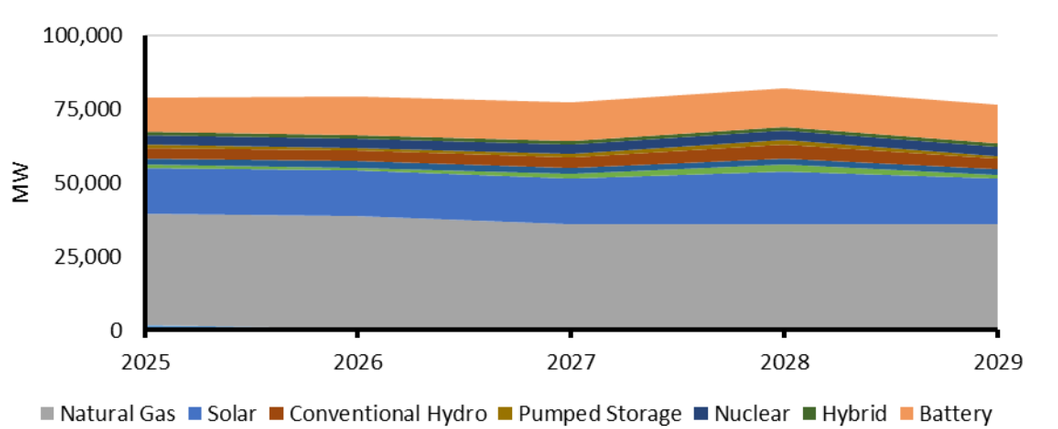
WECC-CA/MX (California/Mexico) is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	56,619	57,274	59,291	60,131	61,289	61,067	62,336	65,876	67,251	69,064
Demand Response	795	797	793	793	793	794	794	794	794	794
Net Internal Demand	55,824	56,477	58,499	59,338	60,496	60,273	61,542	65,082	66,457	68,269
Additions: Tier 1	9,700	11,074	11,128	11,546	11,074	11,990	11,990	12,437	12,047	11,990
Additions: Tier 2	3,349	5,628	5,727	11,483	10,121	17,017	17,017	22,135	23,212	24,650
Additions: Tier 3	9	19	19	22	19	321	321	326	322	321
Net Firm Capacity Transfers	1,509	1,828	2,760	1,953	448	357	342	898	317	314
Existing-Certain and Net Firm Transfers	71,707	70,921	69,827	73,373	66,866	66,142	63,916	68,939	64,533	63,888
Anticipated Reserve Margin (%)	45.8%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25.0%	15.2%	11.1%
Prospective Reserve Margin (%)	51.8%	55.1%	48.2%	62.5%	45.6%	57.9%	51.0%	59.0%	50.2%	47.3%
Reference Margin Level (%)	17.4%	17.4%	16.4%	17.4%	16.6%	16.4%	16.1%	16.3%	14.9%	15.3%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls below the RML in Summer 2034, but the RML is covered by the PRM, which includes Tier 2 resource additions.
- Starting in Summer 2029 onward, CA/MX shows a shortfall of existing-certain and net firm transfers. However, with planned generation resource additions the shortfalls are eliminated. Imports may be necessary if the new resources were to be significantly delayed. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 2 resources and primarily correspond with the evening down ramp of solar and lingering demand after peak.
- The peak hour of demand for CA/MX occurs in the summer. Total internal demand at peak hour is expected to grow from about 56.4 GW in 2024 to 69.1 GW in 2034, a 22.5% load growth over the forecast horizon. The average annual growth rate is 2.07%.
- Diablo Canyon, a 2.2 GW nuclear site, will no longer be retired by 2025 and is now slated to be retired in 2030.

WECC-CA/MX Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	1,572	466	466	465	466
Coal*	1,122	16	16	15	16
Petroleum	185	185	185	184	185
Natural Gas	38,180	38,180	35,565	35,504	35,506
Biomass	726	726	727	726	726
Solar	15,464	15,464	15,501	17,990	15,464
Wind	1,158	1,158	1,428	2,144	1,158
Geothermal	2,004	2,059	2,061	2,056	2,059
Conventional Hydro	3,582	3,582	3,838	4,727	3,582
Pumped Storage	889	889	951	1,710	889
Nuclear	3,282	3,282	3,287	3,283	3,282
Hybrid	32	32	34	39	32
Other	32	32	32	32	32
Battery	12,792	14,111	14,119	14,106	14,111
Total MW	79,898	80,166	78,194	82,967	77,492
Total MW*	79,448	79,716	77,744	82,517	77,042
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

The ARM falls below the RML in the summer of 2034. With the addition of Tier 2 resources, reserve margins remain above RML. Starting in Summer 2029 onward, CA/MX shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

The California Independent System Operator (CAISO) is responsible for much of the BPS that is in CA/MX. CAISO manages the transmission system, oversees transmission planning, and operates the wholesale electricity market for its territory. Other entities in CA/MX include the Balancing Authority of Northern California (BANC), the Imperial Irrigation District (IID), and Mexico's National Center for Energy Control (CENACE), which operates the connected Baja California system.

CAISO Only: The ARM falling below the RML in Summer 2034 and the shortfall of existing-certain and net firm transfers in Summer 2029 is consistent when looking at CA/MX or solely at CAISO. The RML of CAISO averages 0.7% higher than the CA/MX region RML over the LTRA horizon. This is due to the exclusion of natural gas and coal resource energy contributions from CA/MX entities outside of CAISO. Decreasing baseload generators results in increased variability, which in turn requires a greater RML to maintain the ODITY threshold. However, the gap between the anticipated, prospective, and existing reserve margins and the RML for CAISO are greater than the broader CA/MX region. The proportion of energy availability to anticipated net internal demand is larger for CAISO, accounting for this increase.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk in 2026. After 2026, however, WECC's analysis identified periods of unserved energy and load loss in CA/MX during June through October. Of note, this risk is limited to the Mexico portion of CA/MX (i.e., ProbA results for the CAISO do not indicate LOLH or EUE) until 2029, when the risk extends across the entire assessment area.

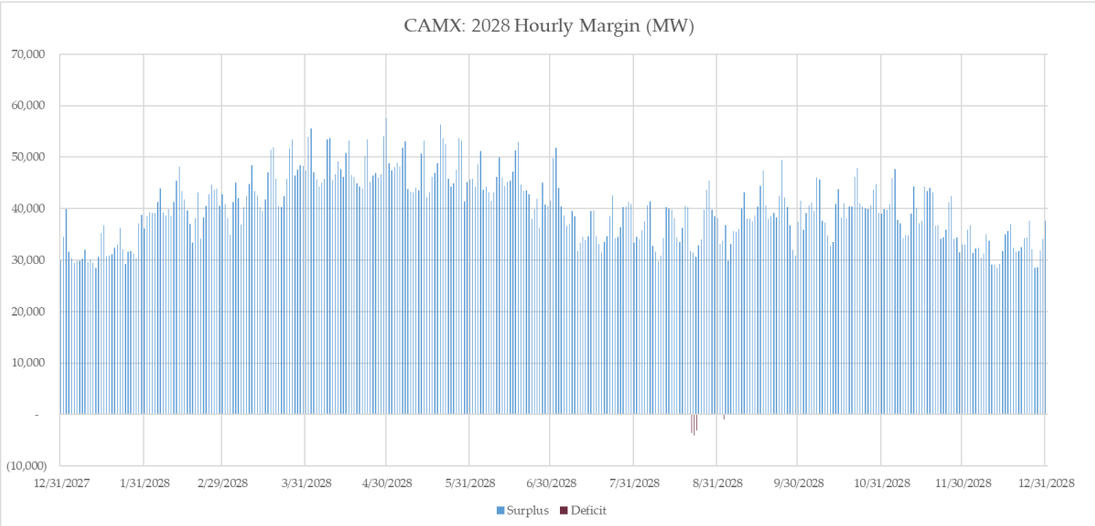
Base Case Summary of Results

	2026*	2026	2028
EUE (MWh)	37,305	0	19,662
EUE (PPM)	136	0	70.07
LOLH (hours per year)	0.721	0	0.38
Operable On-Peak Margin	30.7%	43.2%	41.2%

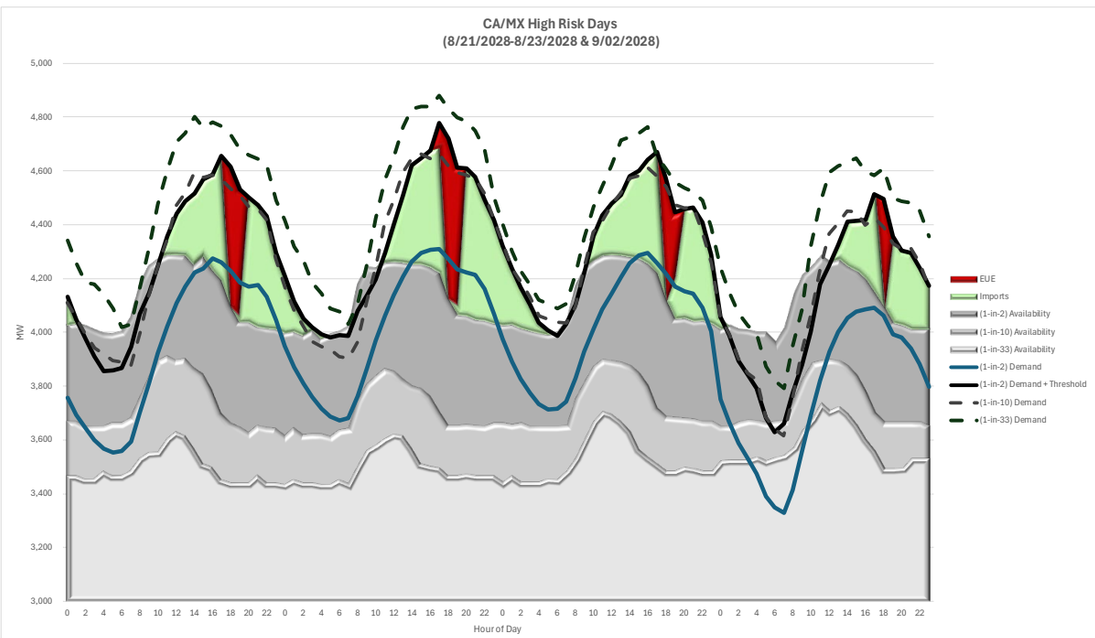
* Provides the 2022 ProbA Results for Comparison

Though the hour and month of peak demand are the same for both CAISO and the broader CA/MX region, CAISO shows the greatest amount of EUE and LOLH in September, whereas CA/MX shows the greatest amount of EUE and LOLH in August. This coincides with the seasonal reduction of solar irradiance in the fall and CAISO having a proportionally larger share of solar resources than the CA/MX region. Excluding regions external to CAISO results in a 96% reduction in LOLH events and EUE over the LTRA horizon.

The hour of peak demand in summer occurs at 5:00 p.m. The hours of highest risk, however, occur during periods after the peak demand hour as solar PV resource output diminishes. There is no LOLH projected for 2026; however in 2028, the ProbA reveals some LOLH between the hours of 5:00 and 8:00 p.m.



Icicle Plot with Hourly Surplus and Deficits for CA/MX in 2028



Demand

The peak demand for CA/MX occurs in the summer. The peak hour for total internal demand is expected to grow from about 56.4 GW in 2024 to 69.1 GW in 2034, a 22.5% load growth over the forecast horizon. The average annual growth rate is 2.07%. Transportation and building electrification are the primary drivers of demand growth.

CAISO Only: The demand forecast for CAISO grows at a slightly higher rate than the broader CA/MX region, with a load growth of 25.2% over the LTRA forecast horizon, and an average annual rate of 2.1%.

Demand-Side Management

A portion of the near-term decline in controllable and dispatchable DR for Summer 2024 is partly driven by regulatory changes in the CA/MX region. This includes making resource adequacy DR crediting adjustments based on historical performance and increasing DR availability requirements. The California Public Utilities Commission (CPUC) determined resource adequacy values of utility DR were overestimated during high load days. In response, the CPUC removed transmission gross-ups and some credits from utility DR resource adequacy values starting in 2024. The CPUC also directed that DR resource adequacy capacity must be available during all days the ISO calls a flex alert or issues a grid warning or on which the governor's office has issued an emergency notice, representing a significant increase in required availability. In addition, the CPUC now requires all DR capacity to be available a minimum of three days per week for at least four hours per day.

For CAISO, energy efficiency and conservation drops significantly when excluding non-CAISO entities from the CA/MX region. The entities outside of CAISO account for an average of 70% of the energy efficiency and conservation DSM for the CA/MX region for the LTRA timeframe.

Distributed Energy Resources

BTM DERs are difficult to measure due to data-gathering barriers. CAISO allows seven DER aggregators as market participants for energy and ancillary services. Additionally, PG&E's Partnership Pilot includes new or existing solar, storage, energy efficiency and demand response used via third party DER providers, vendors, or aggregators.

Generation

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand caused by increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
CA/MX is showing increasing amounts of exports to the northwest, especially during winter months.

Transmission
Seventeen transmission projects with 500 kV and higher are planned.

Reliability Issues
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

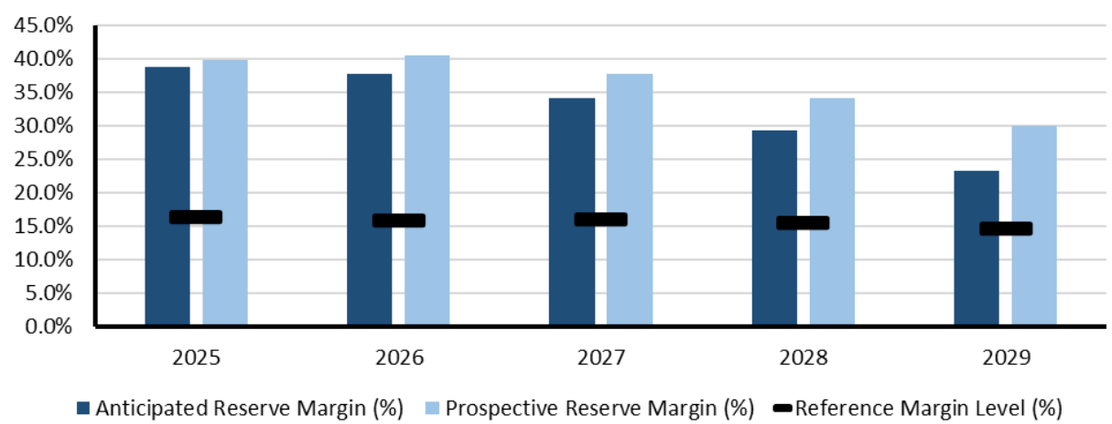


WECC-NW

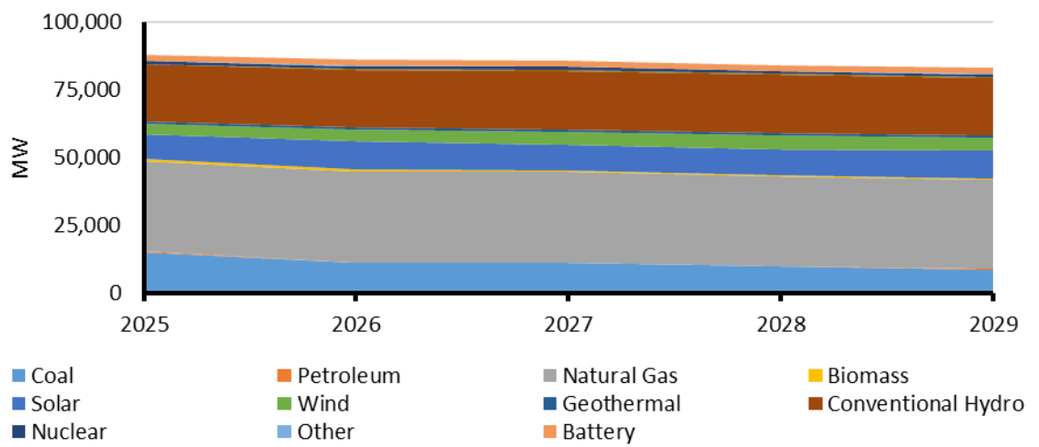
WECC-NW (Northwest) is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	68,274	69,745	71,580	73,626	75,079	75,917	76,736	77,462	78,316	78,835
Demand Response	806	808	811	814	806	809	812	814	817	820
Net Internal Demand	67,469	68,936	70,768	72,811	74,273	75,108	75,925	76,647	77,499	78,016
Additions: Tier 1	7,000	9,386	9,295	9,489	9,752	9,752	10,141	10,141	9,915	10,141
Additions: Tier 2	788	1,955	2,628	3,595	5,046	6,593	7,258	7,273	6,935	7,253
Additions: Tier 3	2,945	8,874	14,008	21,247	28,296	33,802	40,239	42,260	41,876	43,809
Net Firm Capacity Transfers	5,627	8,796	9,087	9,863	8,462	6,037	2,783	2,423	2,370	2,140
Existing-Certain and Net Firm Transfers	86,609	85,564	85,605	84,618	81,788	78,094	74,003	73,297	72,810	71,446
Anticipated Reserve Margin (%)	38.7%	37.7%	34.1%	29.3%	23.3%	17.0%	10.8%	8.9%	6.7%	4.6%
Prospective Reserve Margin (%)	39.9%	40.6%	37.8%	34.2%	30.0%	25.7%	20.4%	18.4%	15.7%	13.9%
Reference Margin Level (%)	16.3%	15.8%	15.9%	15.4%	14.7%	14.5%	14.3%	14.2%	14.4%	13.8%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls below the RML starting in Summer 2031. With the addition of Tier 2 capacity, the PRM stays above the RML for all years in the LTRA time horizon.
- Starting in Summer 2029 onward, the Northwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed. Five GW of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar and wind, supported by BESS. Supply chain issues preventing the construction of BESS resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 3 resources.
- The Northwest is dual peaking, so the peak hour can occur in either the summer or the winter. Probabilistic modeling efforts show a peak in the summer for this LTRA. The summer peak for the total internal demand is expected to grow from about 66.4 GW in 2024 to 78.8 GW in 2034, which is lower than in the previous LTRA. This represents a nearly 18.7% load growth over the forecast horizon, with an average growth rate of 1.73%.

WECC-NW Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	14,965	11,031	11,021	9,667	8,761
Coal*	14,661	10,223	10,607	9,349	8,060
Petroleum	321	321	319	319	316
Natural Gas	33,452	33,636	33,304	32,954	32,749
Biomass	729	723	683	683	604
Solar	9,086	10,191	9,350	9,431	10,379
Wind	3,924	4,566	4,939	4,939	4,561
Geothermal	884	934	933	1,007	997
Conventional Hydro	21,003	21,000	21,542	21,522	20,958
Pumped Storage	373	373	375	375	373
Nuclear	1,096	1,096	1,096	1,096	1,096
Other	64	64	64	64	64
Battery	2,084	2,219	2,188	2,188	2,219
Total MW	87,981	86,154	85,814	84,245	83,077
Total MW*	87,679	85,346	85,398	83,926	82,377
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-NW Assessment

Planning Reserve Margins

The ARM falls below the RML starting in Summer 2031. With the addition of Tier 2 capacity, the PRM stays above the Reference Margin for all years in the LTRA time horizon. Starting in Summer 2029 onward, the Northwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

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

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

Imports to the Northwest from the CA/MX region grow throughout the LTRA forecast horizon. A calm, cloudy, extreme heat event occurring in the Northwest and CA/MX regions simultaneously poses a risk to the Northwest by limiting surplus energy in CA/MX to send northward.

Energy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio. More variability in energy output requires a greater reserve margin to maintain resource adequacy.

For 2026 and 2028, the peak hour occurs in August at HE 17:00. LOLH and EUE are not forecast in 2026 and only occur for a single hour in 2028. The LOLH occurred in August at HE 19:00, slightly after peak. The LOLH corresponds with the declining solar availability in the evening while demand remains high.

Demand

The Northwest is dual peaking, so the peak hour can occur in either the summer or the winter. Probabilistic modeling efforts show a peak in the summer for this LTRA. The summer peak for the total internal demand is expected to grow from about 66.4 GW in 2024 to 78.8 GW in 2034, which is lower than in the previous plan. This represents a nearly 18.7% load growth over the forecast horizon, with an average growth rate of 1.73%. There are significant differences between balancing areas, with some showing large load growth impacts while others showing a slight decrease in demand. Entities reporting large load growth cite new data centers as a primary driver.

Demand-Side Management

In the Northwest, Idaho Power implements a substantial dispatchable DR program focused on the agricultural sector with its Irrigation Peak Rewards Programs. This allows Idaho Power to remotely turn off specific irrigation pumps a minimum of four times during the summer. Participation varies year to year based on factors such as the availability of water and program parameters. In 2022, the utility lengthened the season and included additional evening hours, which drove some reduction in participation that carried over to the Summer 2024 availability.

PacifiCorp states in its most recent Integrated Resource Plan (IRP) that it hopes to reach 1,123 MW of demand response by 2042 in its preferred portfolio plan, which is a 21% increase by 2042 from its previous plan. PacifiCorp's dispatchable DR programs include residential, small commercial air-conditioner load control, irrigation load management, and 203 MW of interruptible contracts.

The Public Service Company of Colorado (PSCo) also offers a wide array of DR programs, such as Saver's Switch, which is a program where the air-conditioning unit of a customer may be controlled

remotely and cycled during extreme heat events. Peak Day Partners allows for the direct load control and reduction of customers 0.5 MW or greater in size when system peaking conditions are met. The Interruptible Service Credit Option (ISOC) is a program where customers agree to reduce consumption in return for a rate discount with non-compliance being met with a fee.

Distributed Energy Resources
BTM DERs are difficult to measure due to data-gathering barriers. One example is Idaho Power's filing of annual DER Resources Status Reports by customer class and resource type, such as in 2023.

Generation
Five GW of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar, wind, and BESS, further increasing variability in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of BESS resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high.

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
The Northwest is showing greatly increasing import needs over the 10-year time horizon, especially in the winter months. Most of the imports in the model simulations come from CA/MX, with a smaller portion coming from BC**.**

Transmission
Twelve transmission projects with 500 kV and higher are planned.

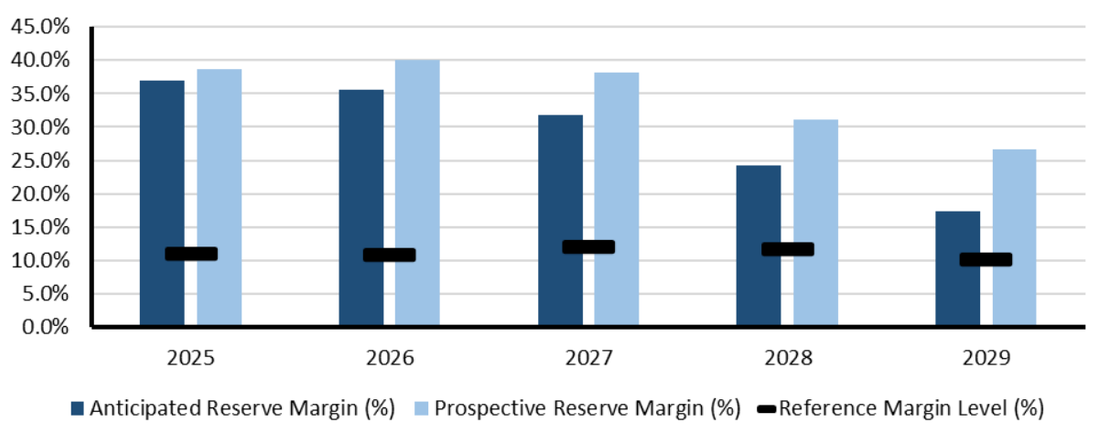


WECC-SW

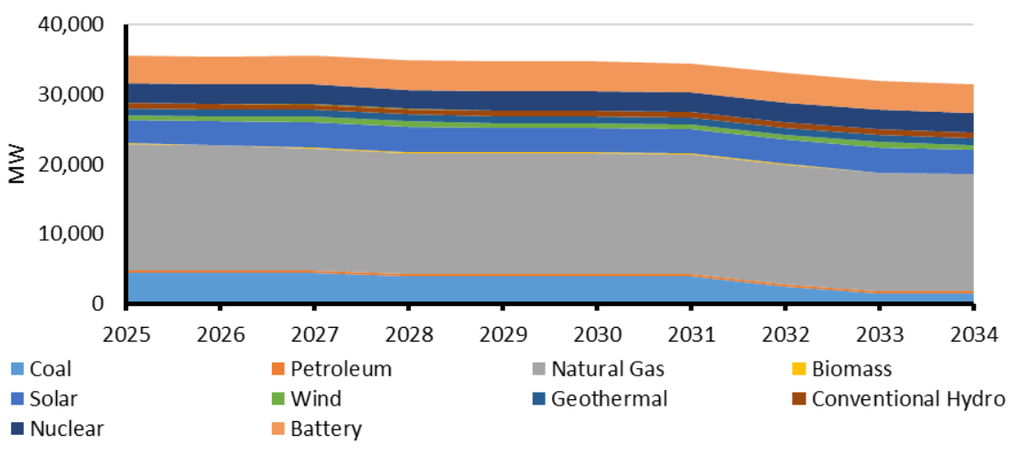
WECC-SW (Southwest) is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 Western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	28,347	29,184	30,098	30,905	31,684	32,401	33,082	33,676	34,301	34,886
Demand Response	417	392	396	424	373	389	392	396	424	373
Net Internal Demand	27,930	28,792	29,702	30,481	31,311	32,012	32,690	33,279	33,876	34,512
Additions: Tier 1	5,140	5,251	5,656	5,656	5,557	5,557	5,557	5,557	5,656	5,557
Additions: Tier 2	475	1,305	1,899	2,079	2,932	2,932	2,966	2,984	3,221	2,984
Additions: Tier 3	40	677	1,148	2,589	3,113	4,438	5,734	7,479	8,960	10,027
Net Firm Capacity Transfers	2,651	3,556	3,554	2,966	2,045	928	716	320	322	0
Existing-Certain and Net Firm Transfers	33,110	33,784	33,491	32,212	31,187	30,070	29,644	27,787	26,645	25,956
Anticipated Reserve Margin (%)	36.9%	35.6%	31.8%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-8.7%
Prospective Reserve Margin (%)	38.6%	40.1%	38.2%	31.1%	26.7%	20.4%	16.8%	9.2%	4.9%	0.0%
Reference Margin Level (%)	11.0%	10.8%	12.0%	11.7%	10.2%	10.1%	9.9%	9.7%	10.8%	9.4%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML until Summer 2031, and the PRM falls below the RML in Summer 2032.
- Starting in Summer 2028 onward, the Southwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 3 resources. Both supply chain and zoning issues have been cited as inhibiting project completion.
- The Southwest's peak demand in summer is forecast to grow at an average of 2.49%. Over the LTRA horizon, the forecast grows by a total of 27.8%, which is the highest forecasted growth in the WECC region. The Southwest's total internal demand forecast is nearly the same as last year's over the near and medium term, with a slight drop from last year's in the longer term, growing from a summer peak of 27.3 GW in 2024 to 34.9 GW by 2034.
- Natural gas derates during extreme heat events are a risk for the Southwest as these resources make up a large share of the resource portfolio in the area.

WECC-SW Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	4,436	4,436	4,432	3,939	3,941
Coal*	4,432	4,432	4,148	3,655	3,657
Petroleum	323	323	322	322	323
Natural Gas	18,165	17,933	17,520	17,323	17,343
Biomass	82	82	82	82	82
Solar	3,354	3,354	3,628	3,628	3,479
Wind	628	695	799	799	695
Geothermal	1,047	1,047	1,047	1,047	1,047
Conventional Hydro	721	721	721	721	721
Pumped Storage	104	104	104	104	104
Nuclear	2,724	2,724	2,711	2,711	2,724
Battery	4,016	4,061	4,226	4,226	4,240
Total MW	35,599	35,479	35,593	34,902	34,698
Total MW*	35,595	35,475	35,309	34,618	34,414
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-SW Assessment

Planning Reserve Margins

The ARM does not fall below the RML until Summer 2031, and the PRM falls below the RML in Summer 2032. This indicates that imports may be necessary if new resources were to be significantly delayed, as Tier 3 resources will be required for reserve margins to meet the RML. Starting in Summer 2028 onward, the Southwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	84	0	19
EUE (PPM)	1	0	0.13
LOLH (hours per year)	0.003	0	0.00
Operable On-Peak Margin	18.3%	33.8%	22.5%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment. Another report produced is a WECC report called the WARA.

For 2026 and 2028, the peak hour occurs in July at HE 17:00. LOLH and EUE are not anticipated in 2026 and are minimal in 2028. LOLH was only observed in August at HE 19:00. The LOLH corresponds with the evening down ramp of solar and lingering demand after peak.

Due to the significant share of natural gas resources in the Southwest portfolio, a concern for the Southwest is natural gas derates during extreme heat events. A strategy to assist with resource planning is to construct derate curves for natural gas resources as a function of temperature. Resource procurement practices have also changed to focus on adding resources that have no dependence on temperature.

Demand

The Southwest has the highest rate of load growth in the Western Interconnection for the LTRA horizon. Large industrial and commercial load additions, such as data centers, have been cited as the reason for this growth.

The Southwest's peak demand in summer is forecast to grow at an average of 2.49%. Over the LTRA horizon, the forecast grows by a total of 27.8%. The Southwest's total internal demand forecast is nearly the same as last year's over the near and medium term, with a slight drop from last year's in the longer term, growing from a summer peak of 27.3 GW in 2024 to 34.9 GW by 2034.

Demand-Side Management

Arizona Public Service (AZPS) has numerous DSM pilots and programs, such as the Residential Energy Storage Pilot and Commercial Advanced Rooftop Controls. In the Residential Energy Storage Pilot, residents may install a small BESS at their residence and enable it to be dispatched by AZPS in response to grid needs 100 times a year, but not below 20% of its capacity. AZPS is projecting an almost 50 MW increase in available DR from 2024 to 2025.

In 2023, the Salt River Project (SRP) subscribed 87 MW of DR capability through the installation of 76,143 smart thermostats and enrolled over 500 businesses as interruptible customers providing 41 MW of controllable DR capacity. The SRP aims to achieve 300 MW of dispatchable DR capability by 2035.

The Public Service Company of New Mexico (PNM) operates the Peak Saver and Power Saver programs. Peak Saver reduces demand from commercial customers greater than 50 kW in size during peak demand periods, and the Power Saver program cycles the compressor of air conditioners to reduce peak demand in the summer. One hundred hours of curtailment are available for both

programs with a four-hour limit per curtailment, and it was found that both programs combined reduce peak demand by an average of 45 MW per curtailment event.

El Paso Electric (EPE) operates a smart thermostat program to cycle air conditioners with the potential to achieve 50 MW of relief by 2040.

Additionally, AZPS, SRP, PNM, and EPE all offer time of use (TOU) rate structures for their customers.

Distributed Energy Resources
BTM DERs are difficult to measure due to data gathering barriers. In the Southwest, NV Energy has added DER plans to its triennial IRPs.

Generation
Southwest entities have slightly under 10 GW of nameplate capacity Tier 1 solar resources planned between 2024 and 2028. Supply chain issues resulting in project delays or failure of completion are a concern for the Southwest. Zoning issues prohibiting the construction of new solar assets are also an issue.

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand caused by increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
The Southwest is not showing a significant increase in reliance on imports in the model, with peak exports occurring between 5:00 p.m. and 10:00 p.m.

Transmission
Twelve transmission projects with 500 kV and higher are planned.

Reliability Issues
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load[39] for the summer and winter of each year.[40] Projected total internal demand is based on normal weather (50/50 distribution)[41] and includes the impacts of distributed resources, EE, and conservation programs.
Net Internal Demand	This is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[42]**	**Load Forecasting Entity**
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
MRO-SPP	Summer	Noncoincident	SPP LSEs
NPCC-Maritimes	Winter	Noncoincident	Maritimes sub-areas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro-Québec
PJM	Summer	Coincident	PJM
SERC-East	Summer	Noncoincident	SERC LSEs
SERC-Florida Peninsula	Summer	Noncoincident	
SERC-Central	Summer	Noncoincident	
SERC-Southeast	Summer	Noncoincident	
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-AB	Winter	Noncoincident	WECC BAs, aggregated by WECC
WECC-BC	Winter	Noncoincident	
WECC-CA/MX	Summer	Noncoincident	
WECC-NW	Summer	Noncoincident	

[39] Glossary of Terms Used in NERC Reliability Standards.

[40] The summer season represents June–September and the winter season represents December–February. In this assessment, the year of a winter period is referred to by the year of the month of December (e.g., Winter 2025 is December 2025 – February 2026).

[41] Essentially, this means that there is a 50% probability that actual peak demand will be higher and a 50% probability that actual peak demand will be lower than the value provided for a given season/year.

[42] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval. This is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[42]**	**Load Forecasting Entity**
WECC-SW	Summer	Noncoincident	

Resource Categories

NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy.

Anticipated Resources[43]

- Existing-certain generating capacity: includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct.
- Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements
- Firm capacity transfers (Imports minus Exports): transfers with firm contracts
- Less confirmed retirements[44]

Prospective Resources: Includes all "anticipated resources" plus the following:

- Existing-other capacity: includes capacity to serve load during period of peak demand from commercially operable generating units without firm transmission or other qualifying provision specified in the market construct. Existing-other capacity could be unavailable during the peak for a number of reasons.
- Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements
- Expected (non-firm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation.
- Less unconfirmed retirements.[45]

[43] Projected capacities are inputs to reserve margin calculations and probabilistic assessments. Projections are dependent on official retirement notices to system operators. If no notice is given, capacity projections assume no retirements, even if established trends for resource retirements show declines over past years

[44] Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.

[45] Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

Resource Categories

Generating Unit Status: Status at time of reporting:

- Existing: It is in commercial operation.
- Retired: It is permanently removed from commercial operation.
- Mothballed: It is currently inactive or on standby but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to "Existing" with capacity contributions entered in "Expected-Other." Once a "mothballed" unit is confirmed to be capable for commercial operation, capacity contributions should be entered in "Expected-Certain."
- Cancelled: planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue.
- Tier 1: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[46]
  - Construction complete (not in commercial operation)
  - Under construction
  - Signed/approved Interconnection Service Agreement (ISA)
  - Signed/approved Power Purchase Agreement (PPA) has been approved
  - Signed/approved Interconnection Construction Service Agreement (CSA)
  - Signed/approved Wholesale Market Participant Agreement (WMPA)
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)
- Tier 2: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[47]
  - Signed/approved Completion of a feasibility study
  - Signed/approved Completion of a system impact study
  - Signed/approved Completion of a facilities study
  - Requested Interconnection Service Agreement
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)
- Tier 3: A units in an interconnection queue that do not meet the Tier 2 requirement.

[46] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)
[47] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

Reserve Margin Descriptions
Planning Reserve Margins: The primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile
Anticipated Reserve Margin (ARM): The amount of anticipated resources less net internal demand calculated as a percentage of net internal demand
Prospective Reserve Margin (PRM): The amount of prospective resources less net internal demand calculated as a percentage of net internal demand
Reference Margin Level (RML): The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, system planners use this metric is to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increased demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the RML is a requirement. RMLs can fluctuate over the duration of this assessment period or may be different for the summer and winter seasons. If an RML is not provided by a given assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Methods and Assumptions

How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

- **Adequacy:** The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components
- **Operating Reliability:** The ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

When extreme or otherwise unanticipated conditions result in a resource shortfall, system operators take controlling actions or implement procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area); these actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its LSEs via contract or agreement for curtailment[48]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

System disturbances affect operating reliability when they cause the unplanned and/or uncontrolled interruption of customer demand. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When interruptions spread over a wide area of the grid, they are referred to as "cascading blackouts," the uncontrolled successive loss of system elements triggered by an incident at any location.

The BES is a defined subset of the BPS that includes all facilities necessary for the reliable operation and planning of the BPS.[49] NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),[50] which is defined by the following characteristics.

- **Adequate Level of Reliability:** It is the state that the design, planning, and operation of the BES will achieve when the following reliability performance objectives are met:
  - The BES does not experience instability, uncontrolled separation, cascading,[51] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[52]
  - BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, malicious acts) are managed.

[48] Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards: NERC Glossary of Terms
[49] BES Definition
[50] NERC Informational Filing (to FERC) on the Definition of Adequate Level of Reliability, Docket Number RR06-1, May 10, 2013.
[51] NERC's Glossary of Terms defines Cascading: "Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."
[52] NERC's Glossary of Terms defines Disturbance: "1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load."

- Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

PRMs are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand. Each assessment area has a peak season, summer or winter, for which its peak demand is higher. PRMs used throughout this LTRA are for each assessment area's peak season listed in the load forecasting table of the **Demand Assumptions and Resource Categories**.

NERC assesses resource adequacy by evaluating each assessment area's PRMs relative to its RML—a "target" or requirement based on traditional capacity planning criteria. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss-of-load analysis. On-peak resource capacity reflects expected output at the hour of peak demand. Because the electrical output of VERs (e.g., wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. Based on the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

Adequate: The ARM is greater than RML.

Marginal: The ARM is lower than the RML and the PRM is higher than RML.

Inadequate: The ARM and PRMs are less than the RML and Tier 3 resources are unlikely to advance.

Metrics for Probabilistic Evaluation Used in this Assessment

Probabilistic Assessment: Biennially, NERC conducts a probabilistic evaluation as part of its resource adequacy assessment and publishes results in the LTRA.

Loss-of-Load Hours: LOLH is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated by using each hourly load in the given period (or the load duration curve).

LOLH is evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study periods. LOLH does not inform of the magnitude or the frequency of loss-of-load events, but it is used as a measure of their combined duration. LOLH is applicable to both small and large systems and is relevant for assessments covering all hours (compared to only the peak demand hour of each season). LOLH provides insight to the impact of energy limited resources on a system's reliability, particularly in systems with growing penetration of such resources. Examples of such energy limited resources include the following:

- DR programs that can be modeled as resources with specific contract limits, including hours per year, days per week, and hours per day constraints
- EE programs that can be modeled as reductions to load with an hourly load shape impact
- Distributed resources (e.g., BTM solar PV) that can be modeled as reductions to load with an hourly load shape impact
- VERs can be modeled probabilistically with multiple hourly profiles

Expected Unserved Energy: EUE is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours. EUE is an energy-centric metric that considers the magnitude and duration for all hours of the time period and is calculated in MWhs. This measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load). Normalizing the EUE provides a measure relative to the size of a given assessment area (generally in terms of parts per million or ppm).

EUE is the only metric that considers magnitude of loss-of-load events. With the changing generation mix, to make EUE a more effective metric, hourly EUE for each month provides insights on potential adequacy risk during shoulder and nonpeak hours. EUE is useful for estimating the size of loss-of-load events so the planners can estimate the cost and impact. EUE can be used as a basis for reference reserve margin to determine capacity credits for VERs. In addition, EUE can be used to quantify the impacts of extreme weather, common mode failure, etc.

NERC is not aware of any planning criteria in North America based on EUE; however, in Australia, the Australian Energy Market Operator is responsible for planning using 0.002% (20 ppm) EUE as their energy adequacy requirement.[53] This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load-loss reliability component.

On the basis of the two years of the ProbA results, NERC determines the risk in terms of the following:

Normal Risk: Negligible amounts of LOLH and EUE.

Periods of Risk: LOLH < 2 Hours and EUE < 0.002% of total annual net energy.

Significant Risk: LOLH > 2 Hours and EUE > 0.002% of total annual net energy.

Understanding Demand Forecasts

Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electric industry continues to monitor electricity use and generally revise its forecasts on an annual basis or as its resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts of the individual planning entities and LSEs. These resulting forecasts reported in this LTRA are typically “equal probability” forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are electricity demands that have already been reduced to reflect the effects of DSM programs, such as conservation, EE, and time-of-use rates; it is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. The effects of DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, the effects of dispatchable and controllable DR are included in net internal demand.

Future Transmission Project Categories

- **Under Construction:** Construction of the line has begun.
- **Planned** (any of the following):
  - Permits have been approved to proceed
  - Design is complete
  - Needed in order to meet a regulatory requirement

- **Conceptual** (any of the following):
  - A line projected in the transmission plan
  - A line that is required to meet a NERC TPL standard or power-flow model and cannot be categorized as “Under Construction” or “Planned”

Other projected lines that do not meet requirements of “Under Construction” or “Planned”

[53] https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2025–2029)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
MISO	2024-2025 Summer: 9.0% Fall: 14.2% Winter: 27.4% Spring (2025): 26.7%	Planning Reserve Margin	Yes: Established Annually[54]	0.1 day/Year Loss of Load Expectation (LOLE)	MISO
MRO-Manitoba Hydro	12.0%	Reference Margin Level	No	0.1 day/Year LOLE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	15.0%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
MRO-SPP	19.0%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1 day/Year LOLE	SPP Staff, Stakeholders, SPP Regional State Committee.
NPCC-Maritimes	20.0%[55]	Reference Margin Level	No	0.1 day/Year LOLE	Maritimes Sub-areas; NPCC
NPCC-New England	11.3–12.7%	Installed Capacity Requirement	Yes: three year requirement established annually	0.1 day/Year LOLE	ISO-NE, NPCC Criteria
NPCC-New York	15.0%[56]	Installed Reserve Margin	Yes: one year requirement, established annually by NYSRC based on full installed capacity values of resources	0.1 day/Year LOLE	NYSRC, NPCC Criteria
NPCC-Ontario	8.6–19.5%	Reserve Margin Requirement	Yes: established annually for all years	0.1 day/Year LOLE	IESO, NPCC Criteria
NPCC-Québec	10.9–11.8%	Reference Margin Level	No: established Annually	0.1 day/Year LOLE	Hydro-Québec, NPCC Reliability Coordinating Committee
PJM	17.6–17.7%	Installed Reserve Margin	Yes: established Annually for each of three future years	0.1 day/Year LOLE	PJM Board of Managers, ReliabilityFirst BAL-502-RFC-02 Standard
SERC-Central	15.0%[57]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities

[54] In MISO, the states can override the MISO PRM.

[55] The 20% RML is used by the individual jurisdictions in the Maritimes area with the exception of Prince Edward Island, which uses a margin of 15%. Accordingly, 20% is applied for the entire area.

[56] The NERC LTRA RML for NY is 15%; however, there is no PRM criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2025/2026 IRM at 24.4%. All values in the IRM calculation are based upon full installed capacity (ICAP) MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.

[57] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2025–2029)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
SERC-East	15.0%[58]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-Florida Peninsula	15.0%[59]	Reliability Criterion	No: Guideline	0.1 day/Year LOLP	Florida Public Service Commission
SERC-Southeast	15.0%[60]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
Texas RE-ERCOT	13.75%	Target Reserve Margin	No	0.1 day/Year LOLE plus adjustment for non-modeled market considerations	ERCOT Board of Directors
WECC-AB	9.0–13.6%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[61]
WECC-BC	9.8–12.8%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-CA/MX[62]	14.9–17.4%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-NW	13.8–16.3%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-SW	9.4–12.0%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]

[58] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[59] SERC-FP uses a 15% reference reserve margin as approved by the Florida Public Service Commission for non-IOUs and recognized as a voluntary 20% reserve margin criteria for IOUs; individual utilities may also use additional reliability criteria.
[60] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[61] WECC's RML in this table is for the hour of peak demand. Some hours in the year require a higher reserve margin to meet the 0.02% reliability criteria due to the variability in resource availability and resource performance characteristics.
[62] California is the only state in the Western Interconnection that has a wide-area RML, currently 17.5%: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage,

Recommendations and ERO Actions Summary

In addition to the recommendations in the Executive Summary, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. The ERO, industry, vendors/manufacturers, and stakeholders should continue acting on the following recommendations to inform system and operations planning, develop the transmission network, and address resource performance issues attributed to IBR characteristics, cold weather, and fuel supply limitations. The ERO has a range of activities underway to monitor, assess, and reduce long-term BPS reliability risks. The selected ERO activities summarized below will result in new or enhanced Reliability Standards requirements, reliability guidelines, resources, or significant findings and actionable steps for stakeholders to address reliability risks.

LTRA Recommendations and Ongoing ERO Actions

Add new resources with needed reliability attributes and make existing resources more dependable.

1. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric criteria applied to results from probabilistic studies that include load loss, unserved energy, event magnitude, and event duration will support achieving the levels of reliability that are required for modern society.
2. **Address performance deficiencies with existing and future inverter-based resources:** Reliably integrating IBRs onto the grid is paramount, and evidence indicates that the risk of grid vulnerabilities from interconnection practices and IBR performance issues are growing. IBRs include most solar and wind generation as well as new BESS or hybrid generation and account for 85% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred in new geographic areas as recently as the summer of 2023.[63] A common thread with these events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. Based on the findings of a recent NERC alert, more ride-through and ERS capabilities can be enabled within existing solar PV resources to improve performance and support the reliable operation of the BPS.[64] Industry adoption of the recommended practices set forth in NERC reliability guidelines and the NERC alert will reduce risks from IBR performance issues to the grid as NERC also develops mandatory Reliability Standards based on those reliability guidelines. It is also critically important for interconnection processes to include accurate modeling and studies requirements.[65] Guided by NERC's comprehensive Inverter-Based Resources Strategy and in response to FERC Order No. 901, the ERO, industry, and manufacturers should take additional steps to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.[66,67]
3. **Improve the performance of the generating fleet in extreme cold temperatures:** The ERO and industry need to complete enhanced requirements for generator cold-weather performance to address reliability related findings from the FERC, NERC, and Regional Entity joint staff inquiry into the February 2021 cold weather grid outages.[68] Revisions to Reliability Standard EOP-012-2 will improve the effectiveness of the standard and speed the implementation of corrective actions necessary to address unacceptable freezing issues. Findings of the inquiry into Winter Storm Elliott (December 2022) reinforce the urgency of this effort.[69]

[63] See the ERO's extensive IBR event reporting here: NERC Major Event Reports
[64] The NERC Level 2 alert to gather data from solar PV resource owners and issue recommendations can be found here: *Industry Recommendation: Inverter-Based Resource Performance Issues*.
[65] NERC's comprehensive initiatives to reduce IBR risks are detailed here: IBR Quick Reference Guide
[66] NERC IBR Activities
[67] Order No. 901 Work Plan
[68] *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report*
[69] *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott*

LTRA Recommendations and Ongoing ERO Actions

4. **Mitigate fuel-related risks to electricity generation (fuel assurance):** In addition to serving as base and intermediate-load plants, natural-gas-fired generation has become a necessary balancing resource that enables reliable integration of VERs into the dispatch. As a result, the BES has never been more dependent upon the round-the-clock continuity of just-in-time natural gas delivery. The past two winters have seen interruptions of natural gas delivery to generators that resulted in energy deficiencies. Collaborative assessments involving NERC, the Regional Entities, the National Labs, and natural gas and electric power industry participants are needed to identify natural gas fuel supply needs for reliable operation of the BPS. NERC strongly endorses actions to establish reliability rules for the natural gas infrastructure necessary to support the grid as recommended in the Winter Storm Elliott report. Additionally, as part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System,* provides planning guidance.[70]

Initiative	Description	Product/Reliability Solution
Cold Weather Reliability Standards and Activities	New cold weather Reliability Standards adopted by the NERC Board of Trustees in June 2021 went into effect in the United States in 2023. Generator Owners and Generator Operators are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their Reliability Coordinators, Transmission Operators, and Balancing Authorities for use in operating plans. Additional Reliability Standard requirements have been developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity staff report—The February 2021 Cold Weather Outages in Texas and Southcentral United States.* The NERC Board adopted these requirements in October 2023 and directed NERC to file them with regulatory authorities for approval and industry implementation. NERC and the industry are currently developing the remaining Reliability Standard enhancements to address the staff report. Refer to *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* on NERC's standards development page.[71]	Reliability Standards NERC Alerts Event Analysis Reports Lessons Learned
Inverter-Based Resources Strategy	NERC's IBR strategy includes four key focus areas: Risk Analysis, Interconnection Process Improvements, Sharing Best Practices and Industry Education, and Regulatory Enhancements. The statuses of NERC's extensive activities in each area are described in detail in the *IBR Activities Reference Guide*.[72] NERC has investigated and analyzed IBR performance issues during grid disturbances dating back to 2016. Since that time, NERC and its technical groups have published a range of reliability guidelines for studying, modeling, controlling, and interconnecting IBRs. In partnership with many experts from across the industry, NERC maintains an active campaign of education, awareness, and outreach to support its strategy and reduce IBR performance risks. NERC and the RSTC recognized that Reliability Standard requirements would be needed as part of a comprehensive approach to reliability and undertook a full review of existing standards to identify gaps. Several reliability standards projects were initiated following this review. In October 2023, FERC issued Order No. 991, which provided clear direction for the industry to develop requirements that address reliability gaps related to IBR in data sharing, model validation, planning and operational studies, and performance requirements.	Reliability Standards NERC Alerts Reliability Guidelines Event Analysis Reports Lessons Learned Educational Webinars

[70] Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised Guideline also identifies as fuel risks requiring evaluation many of the scenarios industry has encountered during recent periods of extreme cold weather and high demand for natural gas. The revised guideline is under review with the Reliability and Security Technical Committee. The approved and revised draft guideline can be found on the RSTC website: NERC Reliability and Security Guidelines

[71] Project 2021-07

[72] IBR Activities

LTRA Recommendations and Ongoing ERO Actions		
	FERC issued an order in 2022 directing NERC to identify and register owners and operators of currently unregistered bulk power system-connected IBRs.[73] Working closely with industry and stakeholders, NERC is executing a FERC-approved work plan to achieve the identification and registration directive by 2026. Resources are also posted on the Registration page of the NERC website.	
Natural Gas-Electric Interdependence Initiatives	Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised guideline also identifies the fuel risks encountered by industry during recent periods of extreme cold weather and high demand for natural gas. These natural gas supply risks can inform industry's development of planning scenarios. The revised guideline is under review with the RSTC. Refer to the RSTC-Approved Documents page.[74]	Reliability Guideline
Expand the transmission network to deliver supplies from new resources and locations to serve changing loads. 5. **Develop the transmission network:** ISOs and RTOs should continue looking for opportunities to streamline transmission planning processes and reduce the time required for transmission development. However, addressing the siting and permitting challenges that are the most common cause for delayed transmission projects will require regulators and policymakers at the federal, state, and provincial levels to focus attention and provide support.		
Initiative	**Description**	**Product/Reliability Solution**
Interregional Transfer Capability Study (ITCS)	NERC completed the ITCS required by the Fiscal Responsibility Act of 2023 and filed the final report with FERC on November 19, 2024. The ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions. However, the ITCS is not a transmission plan or blueprint. Transmission expansion analysis, resource plans, and other inputs must be considered in effective system planning. The ITCS is designed to provide foundational insights that facilitate stakeholder analysis and actions. Due to the interconnected nature of the BPS, NERC will extend the study beyond the congressional mandate to identify and make recommendations for transfer capabilities from the United States to Canada and among Canadian provinces. The Canadian analysis will be published in 2025. See **Interregional Transfer Capability Study (**ITCS).	ERO Study and Recommendations

[73] FERC Order Issued November 17, 2022
[74] RSTC Approved Documents

LTRA Recommendations and Ongoing ERO Actions

Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system.

6. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric approaches to resource adequacy using load loss, unserved energy, and event magnitude and duration criteria and results from probabilistic studies will support achieving the levels of reliability that are required for modern society.

7. **Resource contributions must be accurately represented in resource planning, wholesale electricity markets, and operating models:** Resource Planners and wholesale market designers must use appropriate methods for determining the contribution of resources to meeting demand. Weather-dependent resources, fuel supplies, and demand profiles result in seasonal risks. This can be seen in the increasing winter resource adequacy risks observed in the 2024 ProbA for many traditionally summer-peaking areas. ISO/RTOs can help reduce seasonal risks by implementing seasonal resource adequacy procurement (e.g., spring, summer, fall, winter) based on reserve requirements and resource performance that are tailored to each season. The explosive growth of BESS and hybrid resources seen in most areas requires additional details to be incorporated into operating and planning models, such as state of charge, BESS duration, and BESS operating mode.

8. **Maintain sufficient amounts of flexible resources and essential reliability services:** To maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, dispatchable generators must be available and capable of following changing electricity demand. Retirements of fossil-fired generators are reducing the amounts of dispatchable generation in many areas. As more solar PV and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. Natural-gas-fired generators and hydro generators have traditionally provided this ERS. Battery resources can provide flexibility during short durations, while new wind and solar PV have minimal assured flexibility. Maintaining ERSs is critically important. Resource Planners and wholesale electricity market operators should ensure resources are procured and made available in the long-range resource portfolio as part of the planning process; markets and other mechanisms need to be in place to deliver weather-ready resources with sufficient energy and ERS capabilities to the operators. [75]

9. **Include energy risks and extreme weather scenarios in resource and system planning:** Industry and regulators need to conduct all-hours analyses for evaluating and establishing resource adequacy and include extreme conditions in integrated resource planning and wholesale market designs. While more sophisticated capabilities for assessing extreme event risk are being developed, scenario planning can be more readily incorporated in resource and system planning. Scenarios should consider the potential effects of wide-area, long-duration extreme weather events, including the impact they can have on natural gas fuel supplies and on the interconnected energy system. NERC and the industry should continue to prioritize completion of new reliability standards supporting energy assurance in operating and planning time horizons, and for the assessment of extreme heat and cold weather events in transmission system planning.

10. **Accommodate the growth of DERs:** Preparing the grid to operate with increasing levels of distributed resources is a priority for most areas. Data sharing, models, and information protocols are needed to support BPS planners and operators. Industry must continue to evaluate potential reliability concerns associated with increasing DER penetration and DER performance and, when necessary, develop reliability standards requirements to address identified gaps. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. ISO/RTOs must consider how the implementation of DER aggregators in the wholesale market will affect BPS planning and operations. [76]

[75] NERC ERS Measure 6 Forward Tech Brief

[76] A comprehensive guide to ERO activities on DERs can be found here: DER Activities

LTRA Recommendations and Ongoing ERO Actions		
Initiative	**Description**	**Product/Reliability Solution**
Energy Assessments Initiatives	NERC conducts seasonal long-term and probabilistic reliability assessments and issues reports like this *2024 LTRA* to advise industry and stakeholders of findings on BPS adequacy, including energy adequacy. In recent years, NERC has enhanced the energy risk analysis in seasonal assessments by incorporating deterministic energy risk scenarios and introducing probability-based assessments. NERC's ProbA uses hourly simulations to examine the ability of resources to meet demand over the entire study year, helping to identify energy risks that could otherwise go unaddressed by peak hour reserve margin resource adequacy analysis. NERC reliability assessments continue to evolve as more sophisticated energy assessment tools, models, and capabilities are developed. The RSTC created the Energy Reliability Assessment Working Group (ERAWG) to support wide adoption of technically sound approaches to energy assessments by BPS planners and operators. Working group projects and activities are described on the ERAWG page.[77] The working group is developing a technical reference document to inform registered entities on approaches and considerations for assessing and reducing the risk of energy shortfalls. New and revised Reliability Standards requirements for BPS planners and operators to address energy risks are in development in Project 2022-03 *Energy Assurance with Energy Constrained Resources.*[78] In other Reliability Standard development work, Project 2023-07 *Transmission System Planning Performance Requirements for Extreme Weather* requirements are being developed that will ensure entities consider extreme heat and cold weather scenarios in BPS planning, including the expected availability of the future resource mix.[79]	Reliability Assessments Reliability Standards
Distributed Energy Resources Strategy	NERC has proactively worked with industry stakeholders to identify BPS reliability risks associated with the increasing DER levels and has initiated actions to support broad awareness and education as well as to provide guidance for industry and enhance Reliability Standards where gaps exist. The status of NERC's extensive activities in each area are described in detail in the *DER Activities Reference Guide*.[80]	Reliability Standards Reliability Guidelines Educational Webinars
4: Strengthen relationships among reliability stakeholders.		
Initiative	**Description**	**Product/Reliability Solution**
Ongoing Strategic Engagements	NERC and the Regional Entities engage in frequent dialogue and conduct outreach with regulators and policymakers at the state/provincial, regional, and federal/national levels.	Constructive Partnerships

[77] ERAWG
[78] Project 2022-03
[79] Project 2023-07
[80] DER Activities

Errata

In June 2025, NERC, MRO, and MISO determined that incorrect RMLs were used in the 2024 LTRA for MISO.[81] After applying the correct RMLs, the following changes have been made:

- Figure 1 Risk Area Summary 2025–2029 (p. 6) | MISO changed from High Risk to Elevated Risk
- Table 1: Capacity and Energy Risk Assessment Summary (p. 7)| MISO changed from High Risk to Elevated Risk and Risk Summary updated
- Figure 2: Projected Reserve Margin Shortfall Areas with Announced Generator Retirements (p. 8) | MISO year of shortfall changed from 2025 to 2028 and caption updated
- High Risk Area Details and Elevated Risk Area Details (p. 12) | Removed the description of High Risk, moved relevant discussion of MISO risks to Elevated Risk Area Details, and updated text.
- Figures 3 and 4: MISO Planning Reserve Margins for Summer and Winter (p.13)| Updated with correct RMLs
- Table 12: Anticipated Reserve Margins with Announced Retirements (p. 40) | Footnote added to identify use of UCAP reserve margins for MISO
- MISO Demand, Resources and Reserve Margins (p. 41) | Updated the Reference Margin Level (%) row in the table and updated the Planning Reserve Margins bar graph with correct RMLs; added a note and reference to OMS-MISO Survey
- MISO Highlights (p. 42) | Changed MISO projected capacity shortfall from *2025* to *within the next five years* in the first bullet
- MISO Assessment (p. 43) | Removed the shortfall capacity value in the Planning Reserve Margins section and added a note on the capacity values for existing resources in the MISO tables; removed the statement of ARM falling below RML in the Probabilistic Assessments section

[81] See the *Statement on NERC's 2024 Long-Term Reliability Assessment* issued on June 17, 2025.

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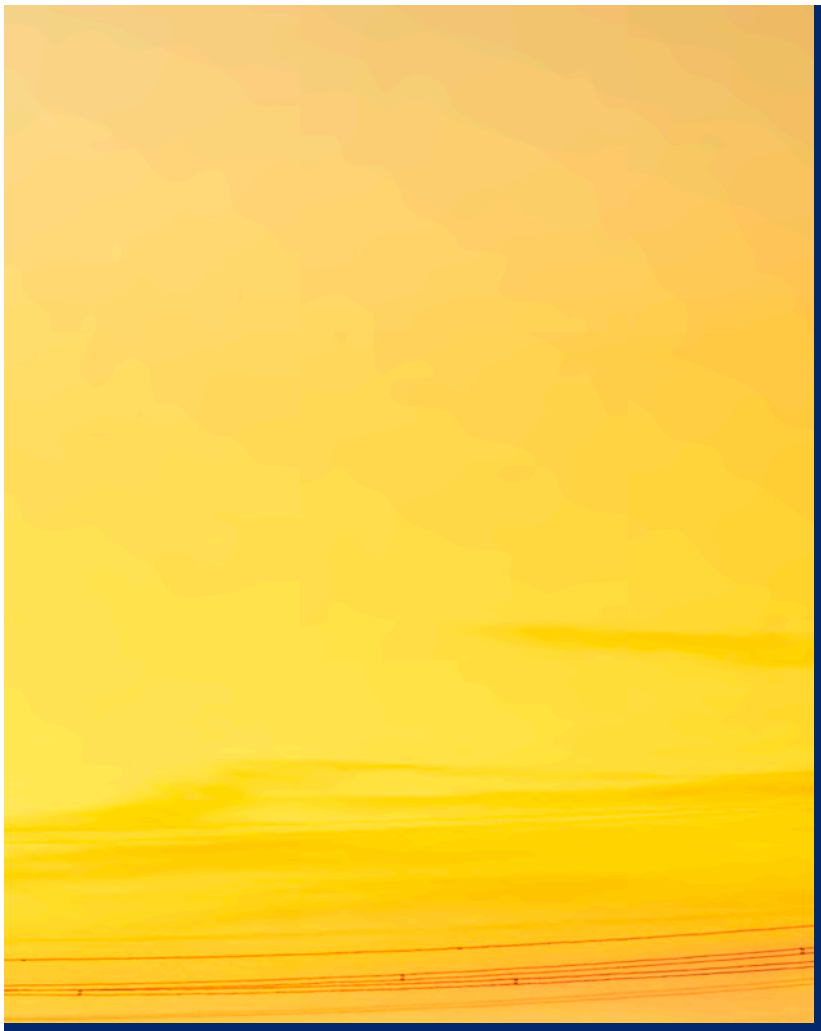
Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

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Exhibit 2-124:
WECC's 2025–26 Winter Reliability Assessment Western Overview

WECC

2025–2026 Winter Reliability Assessment Western Overview



- The Winter Reliability Assessment (WRA) covers the upcoming winter season, providing an evaluation of reliability for projected risk periods.
- Much of the Western Interconnection is expected to be at normal risk this winter, with operating reserves sufficient for meeting normal peak load conditions.
- Two subregions, Northwest and Basin, are expected to be at an elevated risk of electricity shortfalls during potential extreme weather this winter.
- Cold weather Reliability Standards introduced in 2023 have been improved to address recommendations from Winter Storms Elliott and Uri.
- Natural gas production and supply infrastructure performance during the winter conditions of the highest risk periods could have a significant impact on reliability.

NERC Winter Reliability Assessment: Western Overview

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

- The NERC *2025–2026 Winter Reliability Assessment* found that all areas have adequate resources for normal peak load conditions this winter.
- Extreme winter conditions extending over a wide area could result in resource adequacy issues in two subregions: Basin and Northwest. The Northwest is expected to be able to sufficiently meet demand through imports, but Basin could find insufficient imports available to meet demand during a wide-area weather event.
- Natural gas is essential for maintaining reliability in winter. Yet winter conditions can also be the most challenging for natural gas generation, as its production tends to be reduced in extreme cold, supply infrastructure can be affected by issues related to freezing, and generators without secure firm fuel contracts may be unable to get fuel.
- Cold weather reliability standards have been improved to address recommendations from Winter Storms Elliott and Uri, and there has been improved coordination between the electric and natural gas systems, particularly in the Northwest, since the winter storm that hit on Martin Luther King Jr. holiday weekend in January 2024.

Subregion Reliability Highlights

Revised Subregions: WECC divides the Western Interconnection into subregions to analyze resource adequacy and reliability risk at many levels. This year, WECC adopted new subregional boundaries that more accurately reflect operational and planning realities, as well as the footprints of various entities. These new boundaries were used in the WRA.





British Columbia: Peak demand is expected to be roughly the same as last winter in this winter-peaking subregion. Solar nameplate capacity has increased from 2 MW to 17 MW, and hydro capacity is up 5.4% or 1,366 MW. No reliance on imports is expected for reliability.



Alberta: Demand is expected to increase 1% from last winter in this winter-peaking subregion, while the installed capacity has increased 23% since last winter, primarily natural gas.

Northwest: Demand is forecast to increase 9.3% this winter. Retirements of coal and hydro generation have led to a reduction in capacity, but more than 3 GW of new generation has been in development this year, mainly battery storage, solar,

and wind. While there is sufficient generating capacity to meet expected peak demand, Balancing Authorities are likely to rely on energy imports during extreme winter weather that can cause thermal plant outages and curtail wind output.



California: Peak demand is expected to be the same as last winter, and 2.5 GW of new resources have been added to boost capacity by about 5%. Nameplate wind capacity is up almost 27% and solar is up almost 13%. No reliance on imports is expected to be required to maintain resource adequacy.



Mexico: Peak demand is expected to be roughly the same as last winter in this summer-peaking subregion. Although the anticipated reserve margins are down by nearly 8%, the subregion's 83% reserve margin still exceeds the reference margin level of 12.5%. No reliance on imports is expected to be required to maintain resource adequacy this winter.



Basin: Demand is expected to increase 1% since last year. About 7 GW of new wind, solar, and storage were brought online in 2024 and 2025 and is expected to be available this winter. While there is sufficient generating capacity to meet expected peak conditions, a reliance on imports is expected during extreme winter weather due to the potential for plant outages, diminished wind generation, and natural gas fuel supply constraints. However, during a wide-area extreme weather event, there may not be sufficient energy imports available to meet demand.

Rocky Mountain: Demand has increased 1.1% since last winter. Solar nameplate capacity is up 27%, but peak solar availability is down significantly due to the early sunset in winter, and hydro availability is down by around 25% on the peak

hour. Still, no reliance on imports is expected to be required to maintain resource adequacy.

Southwest: Demand is up 2.3% since last winter. Nameplate wind capacity is up 12% and solar has increased 27%. No reliance on energy imports is expected.








CALIFORNIA


MEXICO


BASIN


BASIN


ROCKY
MOUNTAIN


ROCKY
MOUNTAIN

Winter Conditions Affecting the Bulk Power System

Extreme weather remains a top concern for the West. Seasonal forecasts indicate above-normal temperatures for the south and below-normal precipitation conditions for the north. To learn more about the expected winter weather and operating conditions, view the *Reliability in the West Discussion Series: Winter Outlook*.



Temperature Forecast: Dec. '25–Mar. '26

Precipitation Forecast: Dec. '25–Mar. '26

Above: During La Niña, the Pacific jet stream often meanders high into the North Pacific. Southern and interior Alaska and the Pacific Northwest tend to be cooler and wetter than average, and the southern tier of U.S. states—from California to the Carolinas—tends to be warmer and drier than average.

Winter Outlook

Warmer than normal conditions expected across the southern portion of the Western Interconnection, while colder conditions are forecast in the Northwest. Much of the Basin subregion is forecast to have equal chances of below-, near- or above-average temperatures this winter.

The seasonal outlook is influenced by the presence of a weak La Niña, which is expected to continue through February 2026. That could lead to increased precipitation and colder temperatures in Alberta, British Columbia, the Pacific Northwest, and northern California. Additionally, a weak polar vortex could disrupt the jet stream, leading to variable temperature cycles.

Above: U.S. surface map animation from January 14-17, 2024 showing the progression of the Arctic cold front and surface high pressure.

Extreme Weather

Extreme weather not only drives up demand for electricity, it also can impact generation. When these conditions persist for several days, that can lead to problems.

A winter storm that hit the interconnection January 14–17, Martin Luther King Jr. holiday weekend 2024 was both widespread and long-lasting, primarily affecting three subregions—the Northwest, Alberta, and British Columbia. Electricity demand reached record levels at utilities in all three subregions, leading to reliability challenges. Several utilities in the Northwest subregion declared energy emergencies outside of the peak demand periods and relied on imports from other subregions. In Alberta, record-high demand combined with low wind generation and unexpected generation outages led to several energy emergency alerts being issued. No load was lost due in part to an emergency alert asking residents to limit non-essential electricity use.

Electric-Natural Gas Interface

While winter 2024–2025 did not produce a serious weather-driven threat to reliability in the West, the storm that hit over the Martin Luther King Jr. holiday weekend in 2024 has brought increased attention to the importance of coordination between natural gas and electric systems. Natural gas is essential for maintaining reliability in winter, but extreme winter conditions can be the most challenging for natural gas generation. As the resource mix evolves, it is important to understand how the electric and gas systems work together to ensure the reliable operation of the bulk power system. To learn more, view the *Reliability in the West Discussion Series: Natural Gas-Electric Interdependence*.

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

TOP

Built with **Shorthand**

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Exhibit 2-125:
ECHO Pollutant Loading Report (DMR)

An official website of the United States government

ECHO Enforcement and Compliance History Online

<https://echo.epa.gov/>

Pollutant Loading Report (DMR)

TRANS ALTA RAIL, CENTRALIA, 98531

NPDES (National Pollutant Discharge Elimination System) ID:
WA0001546

FRS (Facility Registry Service) ID:
110000490665

Other NPDES (National Pollutant Discharge Elimination System) IDs associated with this FRS (Facility Registry Service) ID:
None

TRI (Toxics Release Inventory) ID(s):
98531CNTRL913BI

Facility Type: NON-POTW

Permit Type: NPDES Individual Permit

Permit Effective Date: 02/01/2022

Permit Expiration Date: 01/31/2027

Major/Non-Major Indicator: Major

Permit Issuance: STATE OF WASHINGTON

Approved Pretreatment Program: N/A

Latitude: 46.755766

Longitude: -122.858237

Facility Design Flow (Permit Application) (MGD (Million gallons per day)):
--

Actual Average Facility Flow (Permit Application) (MGD (Million gallons per day)):
--

Average Facility Flow in 2025 (DMR) (MGD (Million gallons per day)):
--

4-Digit SIC (Standard Industrial Classification) Code:
4911 - ELECTRICAL SERVICES

6-Digit NAICS (North American Industry Classification System) Code:
--

Likely Point Source Category: 423 - Steam electric power generating

Combined Sewer Overflow (CSO) Outfall: N/A

County: LEWIS

Congressional District: Washington's 3rd District

View Detailed Facility Report

View Effluent Charts <https://epa.gov/effluent-charts#wa0001546>

View Permit Limits and Monitoring Requirements

View NPDES Monitoring Data Download

View DMR and TRI Multi-Year Loading Report

Select Reporting Year: 2025 ⚠

Top Pollutants | Facility Loading Calculations ⓘ

Top Pollutants by Pounds (DMR, 2025)

Pollutant Name	Total Pounds (lb/yr)	Max Allowable Load (lb/yr) ⚠

No discharge monitoring data found for this facility.

Download All Data

Top Pollutants by Toxic-Weighted Pounds (TWPE) (DMR, 2025)

Pollutant Name	Total TWPE (lb-eq/yr)	Max Allowable Load (lb-eq/yr) ⚠

No discharge monitoring data for toxic pollutants found for this facility.

Download All Data

– Indicates value contains loads that are calculated using data that has been flagged as potential outliers or data errors.

– Indicates there was one or more exceedances of permit effluent limits for this pollutant sometime during the year. You can hover over the yellow flag to see the load over limit value.

+ ⌂

–

Receiving Water Information

State Water Body Name (ICIS (Integrated Compliance Information System)):
HANAFORD CREEK

Water Body Number (Reach Code):
17100103000573



WBD (Watershed Boundary Dataset) Subwatershed Name / 12-Digit WBD (Watershed Boundary Dataset) HUC (Hydrologic Unit Code) (FRS Derived):
Not found (171001030304)

Listed for Impairment (ATTAINS (Assessment, Total Maximum Daily Load (TMDL) Tracking and Implementation System)):
No

Impairment Class (ATTAINS (Assessment, Total Maximum Daily Load (TMDL) Tracking and Implementation System)):
Not provided.

Cause of Impairment(s) (ATTAINS (Assessment, Total Maximum Daily Load (TMDL) Tracking and Implementation System)):
None

Facility pollutant(s) potentially contributing to impairment:
None

Discharges to a county or watershed with ESA (Endangered Species Act)-listed aquatic species:
Yes

View the U.S. Fish & Wildlife Service Species By County Report

NPDES Program Information

NPDES permit was issued by STATE OF WASHINGTON. Click the appropriate link below for more information on the state or regional program.

Wastewater Treatment Technology Information

The following information comes from EPA's Toxics Release Inventory (TRI) <https://www.epa.gov/toxics-release-inventory-tri-program>. More waste

View State Program Information <https://www.epa.gov/npdes/contact-us-general-information-about-npdes#state>
View EPA Regional Program Information <https://www.epa.gov/npdes/contact-us-general-information-about-npdes#regional>

management and pollution prevention (P2) information is available through this facility's P2 report.

Current Treatment in Place:
Settling / Clarification

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No FEAR Act Data

<https://www.epa.gov/ocr/no-fear-act-data>

Plain Writing

<https://www.epa.gov/web-policies-and-procedures/plain-writing>

Privacy and Security Notice

<https://www.epa.gov/privacy/privacy-and-security-notice>

USA.gov

<https://www.usa.gov/>

White House

<https://www.whitehouse.gov/>

Follow.

Last updated on June 6, 2024

Data Refresh Information

<https://epa.gov/resources/echo-data/about-the-data#sources>

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Exhibit 2-126:
ECHO Effluent Charts

An official website of the United States government

Effluent Charts

Download All Data | Report an Error | Help | Effluent Charts Tutorial

TRANSALTA CENTRALIA GENERATION LLC
913 BIG HANAFORD RD, WA, 98531-9101

NPDES ID: WA0001546

Specify Date Range: 10/01/2022 to 01/02/2026

Compliance Tracking: On

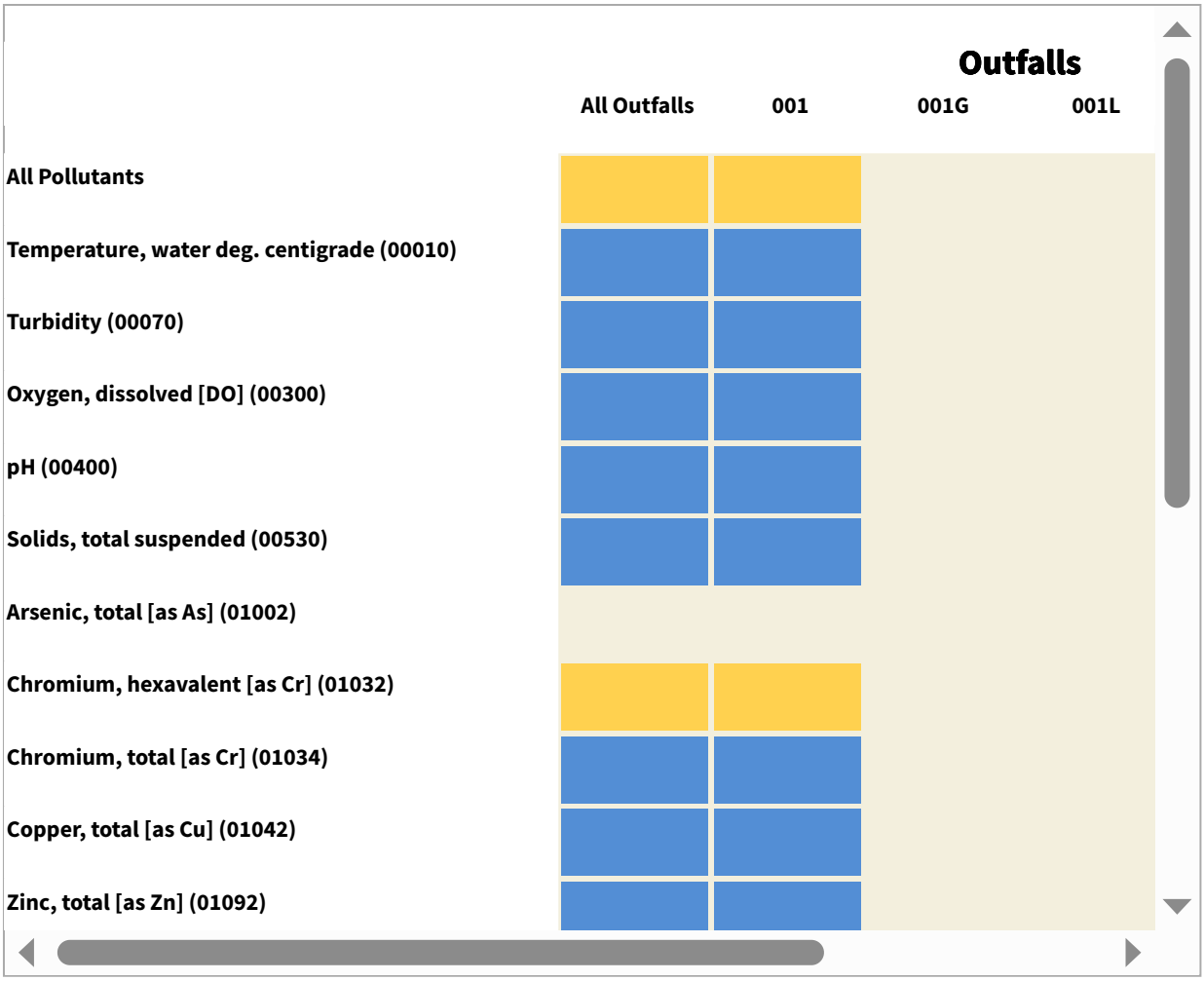
Select any compliance status value to filter the Pollutant/Outfall Summary Grid

- [x] No Violation Identified
- [x] Violation Identified
- [x] Significant/Category I Noncompliance
- [x] No DMR Data Available

Click a cell in the summary grid to display the effluent chart(s). By default the last three years of data are presented.

Download Summary Data

Use the controls above to modify the date range, view charts for a different NPDES ID and/or filter by compliance status.


Outfalls
All Outfalls
001
001G
001L
All Pollutants
Temperature, water deg. centigrade (00010)
Turbidity (00070)
Oxygen, dissolved [DO] (00300)
pH (00400)
Solids, total suspended (00530)
Arsenic, total [as As] (01002)
Chromium, hexavalent [as Cr] (01032)
Chromium, total [as Cr] (01034)
Copper, total [as Cu] (01042)
Zinc, total [as Zn] (01092)

Top of Page

Last updated on May 13, 2024

Data Refresh Information

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Exhibit 2-127:
EPA Basic Information about NO2

Basic Information about NO2

On This Page:

- What is NO_2 and how does it get in the air?
- What are the harmful effects of NO_2?
- What is being done to reduce NO_2 pollution?

What is NO_2 and how does it get in the air?

Nitrogen Dioxide (NO_2) is one of a group of highly reactive gases known as oxides of nitrogen or nitrogen oxides (NO_x). Other nitrogen oxides include nitrous acid and nitric acid. NO_2 is used as the indicator for the larger group of nitrogen oxides.

NO_2 primarily gets in the air from the burning of fuel. NO_2 forms from emissions from cars, trucks and buses, power plants, and off-road equipment.

Effects of NO_2

Health effects

Breathing air with a high concentration of NO_2 can irritate airways in the human respiratory system. Such exposures over short periods can aggravate respiratory diseases, particularly asthma, leading to respiratory symptoms (such as coughing, wheezing or difficulty breathing), hospital admissions and visits to emergency rooms. Longer exposures to elevated concentrations of NO_2 may contribute to the development of asthma and potentially increase susceptibility to respiratory infections. People with asthma, as well as children and the elderly are generally at greater risk for the health effects of NO_2.

NO_2 along with other NO_x reacts with other chemicals in the air to form both particulate matter and ozone. Both of these are also harmful when inhaled due to effects on the respiratory system.

- Learn more about Particulate Matter <https://epa.gov/pm-pollution> and Ozone <https://epa.gov/ground-level-ozone-pollution>.

Environmental effects

NO_2 and other NO_x interact with water, oxygen and other chemicals in the atmosphere to form acid rain. Acid rain harms sensitive ecosystems such as lakes and forests.

- Learn more about Acid Rain <https://epa.gov/acidrain>.

The nitrate particles that result from NO_x make the air hazy and difficult to see though. This affects the many national parks that we visit for the view.

- Learn more about Visibility and Haze <https://epa.gov/visibility>.

NO_x in the atmosphere contributes to nutrient pollution in coastal waters.

- Learn more about Nutrient Pollution <https://epa.gov/nutrientpollution>.

What is being done to reduce NO_2 pollution?

EPA's national and regional rules to reduce emissions of NO_2 and NO_x will help state and local governments meet the National Ambient Air Quality Standard (NAAQS).

- Learn about how air quality standards help reduce NO_2 <https://epa.gov/no2-pollution/setting-and-reviewing-standards-control-no2-pollution>

EPA identifies areas where the air quality does not meet the national NO_2 standards. For these areas, state, local, and tribal governments develop plans to reduce the amount of NO_2 in the air.

- Learn more about NO_2 air quality designations and state implementation plans (SIPs) <https://epa.gov/no2-pollution/applying-or-implementing-nitrogen-dioxide-standards>.

Last updated on July 10, 2025

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Exhibit 2-128:
EPA Sulfur Dioxide Basics

Sulfur Dioxide Basics

- What is SO_2 and how does it get in the air?
- What are the harmful effects of SO_2?
- What is being done to reduce SO_2 pollution?

What is SO_2 and how does it get in the air?

What is SO_2?

EPA's national ambient air quality standards for SO_2 are designed to protect against exposure to the entire group of sulfur oxides (SO_x). SO_2 is the component of greatest concern and is used as the indicator for the larger group of gaseous sulfur oxides (SO_x). Other gaseous SOx (such as SO_3) are found in the atmosphere at concentrations much lower than SO_2.

Control measures that reduce SO_2 can generally be expected to reduce people's exposures to all gaseous SO_x. This may have the important co-benefit of reducing the formation of particulate sulfur pollutants, such as fine sulfate particles.

Emissions that lead to high concentrations of SO_2 generally also lead to the formation of other SO_x. The largest sources of SO_2 emissions are from fossil fuel combustion at power plants andother industrial facilities.

How does SO_2 get in the air?

The largest source of SO_2 in the atmosphere is the burning of fossil fuels by power plants and other industrial facilities. Smaller sources of SO_2 emissions include: industrial processes such as extracting metal from ore; natural sources such as

volcanoes; and locomotives, ships and other vehicles and heavy equipment that burn fuel with a high sulfur content.

What are the harmful effects of SO_2?

SO_2 can affect both health and the environment.

What are the health effects of SO_2?

Short-term exposures to SO_2 can harm the human respiratory system and make breathing difficult. People with asthma, particularly children, are sensitive to these effects of SO_2.

SO_2 emissions that lead to high concentrations of SO_2 in the air generally also lead to the formation of other sulfur oxides (SO_x). SO_x can react with other compounds in the atmosphere to form small particles. These particles contribute to particulate matter (PM) pollution. Small particles may penetrate deeply into the lungs and in sufficient quantity can contribute to health problems.

- Learn more about particulate matter <https://epa.gov/pm-pollution>

What are the environmental effects of SO_2 and other sulfur oxides?

At high concentrations, gaseous SOx can harm trees and plants by damaging foliage and decreasing growth.

SO_2 and other sulfur oxides can contribute to acid rain which can harm sensitive ecosystems.

- Learn more about acid rain <https://epa.gov/acidrain>

Visibility

SO_2 and other sulfur oxides can react with other compounds in the atmosphere to form fine particles that reduce visibility (haze) in parts of the United States, including many of our treasured national parks and wilderness areas.

- Learn more about visibility and regional haze <https://epa.gov/visibility>

Deposition of particles can also stain and damage stone and other materials, including culturally important objects such as statues and monuments.

What is being done to reduce SO_2 pollution?

EPA's national and regional rules to reduce emissions of SO_2 and pollutants that form sulfur oxides (SO_x) will help state and local governments meet the Agency's national air quality standards.

- Learn about how air quality standards help reduce SO_2 <https://epa.gov/so2-pollution/setting-and-reviewing-standards-control-so2-pollution>

EPA identifies areas where the air quality does not meet EPA SO_2 standards. For these areas, state, local, and tribal governments develop plans to reduce the amount of SO_2 in the air.

- Learn more about SO_2 air quality designations and state implementation plans (SIPs) <https://epa.gov/so2-pollution/applying-or-implementing-sulfur-dioxide-standards>

Last updated on January 2, 2026

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Exhibit 2-129:
EPA Particulate Matter (PM) Basics

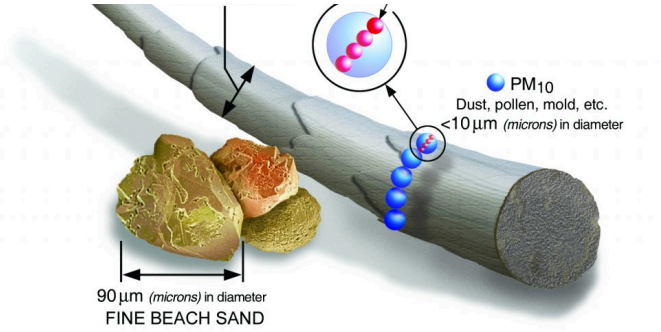
Particulate Matter (PM) Basics

On This Page:

- What is PM, and how does it get into the air?
- What are the harmful effects of PM?
- What is being done to reduce particle pollution?
  - How can I reduce my exposure to PM?

What is PM, and how does it get into the air?

<https://epa.gov/sites/default/files/2016-09/pm2.5_scale_graphic-color_2.jpg>



Size comparisons for PM particles

PM stands for particulate matter (also called particle pollution): the term for a mixture of solid particles and liquid droplets found in the air. Some particles, such as dust, dirt, soot, or smoke, are large or dark enough to be seen with the naked eye. Others are so small they can only be detected using an electron microscope.

Particle pollution includes:

- **PM_{10}**: inhalable particles, with diameters that are generally 10 micrometers and smaller; and

- **$PM_{2.5}$** : fine inhalable particles, with diameters that are generally 2.5 micrometers and smaller.
    - How small is 2.5 micrometers? Think about a single hair from your head. The average human hair is about 70 micrometers in diameter – making it 30 times larger than the largest fine particle.

Sources of PM

These particles come in many sizes and shapes and can be made up of hundreds of different chemicals.

Some are emitted directly from a source, such as construction sites, unpaved roads, fields, smokestacks or fires.

Most particles form in the atmosphere as a result of complex reactions of chemicals such as sulfur dioxide and nitrogen oxides, which are pollutants emitted from power plants, industries and automobiles.

What are the Harmful Effects of PM?

Particulate matter contains microscopic solids or liquid droplets that are so small that they can be inhaled and cause serious health problems. Some particles less than 10 micrometers in diameter can get deep into your lungs and some may even get into your bloodstream. Of these, particles less than 2.5 micrometers in diameter, also known as fine particles or $PM_{2.5}$, pose the greatest risk to health.

Fine particles are also the main cause of reduced visibility (haze) in parts of the United States, including many of our treasured national parks and wilderness areas.

Learn more about health and environmental effects <https://epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm>

What is Being Done to Reduce Particle Pollution?

EPA regulates inhalable particles. Particles of sand and large dust, which are larger than 10 micrometers, are not regulated by EPA.

EPA's national and regional rules to reduce emissions of pollutants that form PM will help state and local governments meet the Agency's national air quality standards. Learn about how air quality standards help reduce PM. <https://epa.gov/pm-pollution/setting-and-reviewing-standards-control-particulate-matter-pm-pollution>

How Can I Reduce My Exposure to PM?

You can use air quality alerts to protect yourself and others when PM reaches harmful levels:

AirNow <https://www.airnow.gov>: Every day the Air Quality Index (AQI) tells you how clean or polluted your outdoor air is, along with associated health effects that may be of concern. The AQI translates air quality data into numbers and colors that help people understand when to take action to protect their health.

- Go to About AirNow <https://www.airnow.gov/about-airnow/> to learn how you can get AQI notifications.
- Also learn how the Air Quality Flag Program <https://www.airnow.gov/air-quality-flag-program/> can help air agencies, schools, and other community organizations to notify their citizens of harmful conditions and adjust outdoor physical activities as needed.

Last updated on May 30, 2025

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-130:
Southwest Clean Air Agency Compliance Evaluation On-Site Inspection Report
(Dec. 12, 2025)

SOUTHWEST CLEAN AIR AGENCY
COMPLIANCE EVLAUATION REPORT
ON-SITE INSPECTION

Date(s) of Inspection: October 23 and November 4, 2025 Date of Report: December 12, 2025

Source Name: TransAlta Centralia Generation, LLC

SWCAA ID: 754

Physical Location: 913 Big Hanaford Road, Centralia, Washington 98531
Mailing Address: 913 Big Hanaford Road, Centralia, Washington 98531
Telephone/e-mail: (360) 330-2306 / Sam_Bocook@transalta.com
Source Contact(s): Sam Bocook, Conrad Wieclaw
Inspection Contact: Sam Bocook

AIRS No.: 53-041-10010 Title V: Yes; Opt-Out: No
SIC and/or NAICS: 4911 / 221112 AOP No.: SW98-8-R5-A
Orders/Permits: 97-2057R1, 01-2403, 05-2636, 08-2779, PSD-01-01 Amendment 2, 09-2876 (non-road engine), Second Revision of Order No. 6426, 11-2972, 11-2984, 12-3016, 16-3188, 16-3202

SWCAA Rep: Clint Lamoreaux
Previous Inspection Dates: October 28, 2024
Inspection Safety Equip. Req'd: steel toe shoes, safety glasses, ear plugs, hard hat

EI Year - 2024
Number of Emission Units: 18

Criteria Emissions (TPY):	Plant Totals	Approximate PTE (inc. nonroad Pump-04, Jetstream)
NO_X	2,607.56	6,761
CO	2,361.24	8,051
VOC	9.76	89.98
SO_2	938.86	5,917
PM	173.38	1,930
PM_{10}	136.31	1,467
$PM_{2.5}$	114.90	1,386
TAP Emissions:	36.36	451
HAP Emissions:	17.87	53.36±

A. Process Description/Background:

The Centralia Coal Plant generates electric energy from a steam driven turbine. Pulverized coal is combusted in a single boiler to create heat that generates pressurized steam used in the turbine. Until December 31, 2020, when "Unit 1" retired, the facility utilized two coal-fired boilers, therefore permits and historical references will frequently refer to two boilers (Unit 1 and Unit 2). Combustion of coal produces emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_X), particulate matter (PM),

carbon monoxide (CO), volatile organic compounds (VOCs), and certain hazardous air pollutants (HAPs) in sufficient quantities to designate the facility as a Title V source of air pollutants.

Until May 4, 2000, PacifiCorp owned the largest share of the Centralia Plant and operated the facility on behalf of all eight utility owners. As of May 4, 2000, TransAlta Centralia Generation, LLC took over ownership of the plant. The plant consists of one 670 net MW unit identified as Unit 2 (Acid Rain Program designation BW22) which is the source of nearly all emissions released from the facility. An auxiliary boiler is used to provide steam for starting the main coal-fired boiler when it is off line. Historically, coal was supplied primarily from the adjacent TransAlta Centralia Mining, LLC (a subsidiary of TransAlta) mine and stacked and reclaimed in the Centralia Plant's coal handling yard. A smaller portion of coal from the Powder River Basin in Wyoming was blended with Centralia coal to meet Btu requirements in the boilers and, potentially, to ensure that the hourly SO_2 emission limit continued to be met. The coal mine ceased active mining operations in November 2006 and currently almost all coal is supplied from the Powder River Basin. Since 2015 a small percentage of coal is supplied coal fines recovered during the reclamation process of the fine coal refuse impoundments formed during the Centralia Mine's coal washing process. The coal mine could conceivably re-open and once again supply coal to the power plant in the future.

Particulate matter from coal combustion is controlled by dual electrostatic precipitators (ESPs) in series. Sulfur dioxide emissions are managed by coal blending and scrubbing of the flue gas. Mercury emissions are controlled by an activated carbon injection system upstream of the second set of ESPs coupled with a sorbent enhancement additive injected into the boiler. The mercury control systems were completed November 24, 2011. NO_X emissions are controlled with low-NO_X burners with coupled over-fire air systems (LNC3) and a selective non-catalytic reduction system (SNCR). The LNC3 controls were installed on Unit 2 in 2001. The SNCR systems were installed on both units in 2012. Emissions of other gaseous pollutants are minimized through good combustion practices. A portion of the fly ash captured in the ESPs is sold and shipped off site while the balance is stockpiled or trucked to the Centralia Mine landfill site. Bottom ash is also sold, stockpiled, or returned to the Centralia Mine landfill site. Additional emission points include the cooling towers, coal storage and handling yard, emergency diesel generators, mist eliminators for turbine lube oil ventilation exhaust, and maintenance activities.

The Centralia Coal Plant can operate continuously 24 hours per day, 7 days per week. The single operating boiler is taken off line for maintenance purposes as conditions dictate, for economy, or reserve shut down. The auxiliary boiler operates only as needed, which is typically less than 120 hours per year.

B. Emission Units/Control Equipment Descriptions:

Summary Table

EU #	Generating Equipment	Emission Control
EU-1	Unit 1 Boiler (BW21) – 670 MW (net), coal fired (Retired)	N/A (Retired)
EU-2	Unit 2 Boiler (BW22) – 670 MW (net), coal fired	CO: Combustion controls NO_X: Combustion controls, SNCR VOC: Combustion controls PM: Dual ESPs, wet scrubber SO_2: Wet scrubber Hg: Sorbent enhancement additive in boiler, carbon injection between ESPs
EU-3	Auxiliary Boiler – 170 MMBtu/hr, oil-fired	Fuel consumption limit
EU-4	Material Handling (Coal Handling, Ash Handling, FGD Bleed Treatment Lime Storage Silo, Limestone Ball Mill)	Coal Handling – minimal emissions, no controls necessary except use of wet suppression at Coal Unloading Facility Ash Handling – baghouse, wet suppression, and enclosure as appropriate FGD Bleed Treatment Lime Storage Silo – Baghouse Limestone Ball Mill – Wet process, full enclosure
EU-5	Turbine Lube Oil Mist Vent 1 (Retired)	N/A (Retired)
EU-6	Turbine Lube Oil Mist Vent 2	Turbine Lube Oil Mist Eliminator 2
EU-7	Black Stop Diesel Generator Engine – 1,445 hp diesel engine (Retired)	N/A (Retired)
EU-8	Journal Shop Welding	Journal Shop Welding Filter
EU-9	Emergency Diesel Generator 1	None
EU-10	Emergency Diesel Generator 2	Ultra-low sulfur fuel, EPA Tier 3 design, operating hours limit
EU-11	Fire Pump Engine (205 hp diesel engine)	Ultra low sulfur fuel, EPA Tier 3 design, operating hours limit
EU-12	Coal Unloading Facility Emergency Diesel Sump Pump Engine (115 hp diesel engine)	Ultra low sulfur fuel, EPA Tier 2 design, operating hours limit
EU-13	SEA System 1	Cartridge-style Fabric Filter
EU-14	SEA System 2	Cartridge-style Fabric Filter
EU-15	Sorbent Silo 1	Cartridge-style Fabric Filter
EU-16	Sorbent Silo 2	Cartridge-style Fabric Filter
EU-17	Fly Ash Bin 11	Baghouse
EU-18	Fly Ash Bin 12	Baghouse

EU #	Generating Equipment	Emission Control
EU-19	Fly Ash Bin 14	Baghouse
EU-20	Fly Ash Bin 14 Air Slide to Bin 11 Air Slide	Cartridge-style Fabric Filter
EU-21	Fly Ash Bin 14 to 6050 Air Slide	Cartridge-style Fabric Filter
EU-22	Fine Coal Handling (Retired)	N/A (Retired)
N/A	Pump-05 Engine (nonroad engine) (John Deere / 4045TF150A)	Ultra low sulfur diesel (≤ 0.0015% S) EPA Tier 1
N/A	Pump-07 Engine (nonroad engine) (John Deere / 4045TF285) Serial Number PE4045L276859	Ultra low sulfur diesel (≤ 0.0015% S) EPA Tier 3
N/A	Jetstream Power Washer (nonroad engine) (John Deere / 6068HF485)	Ultra low sulfur diesel (≤ 0.0015% S) EPA Tier 3

Detailed Descriptions

EU-1 Unit 1 Boiler (Retired)

EU-1 retired at the end of 2020.

EU-2 Unit 2 Boiler

EU-2 consists of the Unit 2 boiler and its exhaust gas flow path including the 470 ft tall stacks (bypass and scrubber) through which the flue gases are discharged to the ambient air. The Unit 2 boiler is a Combustion Engineering coal-fired steam generator equipped with superheat and reheat that combusts pulverized coal in a divided furnace with tangential injection of pulverized coal and combustion air. The eight corners (four in each half of the split furnace configuration) of the boiler are supplied with fuel and air by eight levels of burners, with each level supplied by one of the eight coal pulverizers. A maximum design capacity of 490 tons per hour of coal can be combusted in the boiler. Typically, full load is attained burning 420 tons per hour of average heat content coal by operating seven of the eight pulverizers at rated capacity. Incidental quantities of on-site generated dangerous waste, used oil and grease may also be burned in the boiler. Combustion produces emissions of SO_2, NO_X, CO, PM, VOCs, and HAPs. Flue gases exit the boiler through heat exchangers and pass first through a Koppers electrostatic precipitator (ESP) with a specific collection area of 383 ft^2/1,000 acfm, and then through a Lodge-Cottrell ESP with a specific collection area of 384 ft^2/1,000 acfm for removal of particulate matter. The dual ESP system achieves a collection efficiency of 99.7% or better for particulate matter. Final flue gas treatment occurs in a forced oxidation limestone flue gas desulfurization system (wet scrubber) installed in 2001. The original stack has been retained for bypass operations during emergencies, startup, shutdown, and outages of the flue gas desulfurization system.

Mercury emissions are controlled by an activated carbon injection system upstream of the second set of ESPs coupled with a sorbent enhancement additive injected into the boiler. The mercury control system was completed November 24, 2011. NO_X emissions are controlled with "Low-NO_X Combustion, Level 3" (LNC3) controls consisting of Alstom

concentric firing, low NO_X burners with close coupled and separated over-fire air. The LNC3 controls were installed in 2001.

The SNCR system was installed in 2012 and consists of Nalco Mobotec's Rotamix SNCR system. The system consists of concentrated urea storage, urea dilution, and three levels of diluted urea injection near the top of the boiler. Each urea injection point utilizes an air atomizing nozzle with annular air to allow the urea to be dispersed into the boiler before reacting. Each nozzle can be angled approximately 30 degrees upward or downward. The lowest level of injectors is approximately at the 10.5 floor level. Each of the three horizontal levels consists of six injectors spread across the front of the boiler, with four more injectors slightly above the row of six, for a total of 30 injectors. A single air header with a blower supplies ambient air to all of the annular air supplies on the boiler. The air intake for these blowers is inside the top of the boiler building.

Each SNCR blower or pump has a redundant backup to minimize the possibility of a system outage. As the temperature regime changes with changing boiler load, the levels at which the urea is injected is modified accordingly to ensure the proper injection location.

The following individual pieces of equipment are associated with EU-2:

Equipment	Facility Designation
One Boiler for Unit 2	Unit 2 or BW22
Two ESP units in series	Koppers 21 & 22; Lodge-Cottrell 21A & 22A
Unit 2 wet scrubber	FGD 2

Construction of EU-2 officially commenced (for the purposes of 40 CFR 60) with signing of a construction contract on December 23, 1968. EU-2 commenced commercial operation in September 1972.

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart UUUUU

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	6,744	Yes/No[1]	Yes	No. Permit requires CEMS.
CO	8,042	No	Yes	No. No emission control equipment and the permit requires CEMS.
VOC	86	No	No	No
SO_2	5,913	Yes	Yes	No. Permit requires CEMS.
PM_{10}	1,277	Yes	Yes	Yes. See M20 of Permit.
NH_3	220	No	Yes	No
HF	28	Yes	No	No

[1] SNCR is available but there is no requirement to use the system and there is little likelihood the system will be used in the future.

EU-3 Auxiliary Boiler

EU-3 consists of the auxiliary boiler which is used to provide auxiliary steam throughout the plant when sufficient auxiliary steam is not available from Unit 2, such as during cold startup. The auxiliary boiler is a Babcock & Wilcox watertube steam boiler (National Board number 23173, Washington State ID number 26415-71W) with a rated capacity of 115,000 lb/hr of steam and 170 MMBtu/hr. It combusts No. 2 fuel oil, also known as distillate grade diesel fuel, to produce steam at 150 psig and 500°F and discharges flue gases through a 5 ft diameter steel stack 250 ft in height. EU-3 emits NO_X, SO_2, CO, PM, and VOCs from combustion of No. 2 fuel oil.

Construction of EU-3 officially commenced (for the purposes of 40 CFR 60) with signing of a construction contract on December 23, 1968.

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart DDDDD

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	6.00	No	No	No
CO	1.50	No	No	No
VOC	0.08	No	No	No
SO_2	4.26	No	No	No
PM_{10}	0.99	No	No	No

EU-4 Material Handling

EU-4 consists of all coal handling equipment and operations on the Centralia Plant site, the ash collection and load-out facilities, the FGD Bleed Treatment Lime Storage Silo, and the Limestone Ball Mill. The coal handling equipment receives and stores the coal, reclaims coal from storage piles, and distributes the coal throughout the plant. Historically, coal has been received from the adjacent coal mine and delivered from the Powder River Basin. Most of the coal combusted in the Centralia Plant has been obtained from the adjacent TransAlta Centralia Mining (TCM) mine, which processed coal at its preparation plant and transferred the coal by conveyor to the Centralia Plant. This mine is currently closed. Coal is received by rail car at the Coal Unloading Facility from which it is transferred by conveyor and mobile machinery to storage piles. Note that prior to 2011 there were two Coal Unloading facilities. One located at the West end of the plant site and one located the East end of the plant site. The West Coal Unloading Facility was removed from service in 2011. Except for descriptions in historical context all coal is unloaded at a single point: the Coal Unloading Facility formerly the known as the East Coal Unloading Facility. In 2007 the permittee received an Air Discharge Permit to construct the Coal Unloading Facility. A traveling bucket-wheel stacker-reclaimer transfers yard conveyor transported coal to or from ready storage piles. In addition, a coal blending system installed in 2001 supplies coal to the plant from the ready storage pile. Dust suppression is provided to minimize generation of fugitive dust as coal is transported to the silos and pulverizers.

Fly ash is collected in storage silos and sent off-site via one of two load-out facilities. A portion of the fly ash is sold and loaded into trucks by an off-site contractor who is contractually responsible to the permittee for operation and air quality compliance of these truck-loading facilities at the Plant. Permittee is ultimately responsible for compliance under the Clean Air Act at this facility. The other load out operated by the Plant is used to dispose of fly ash in the TCM mine. Bottom ash is dewatered in settling tanks and loaded while damp into trucks for transport to the TCM mine as backfill or sold for off site use.

The following individual pieces of equipment are associated with EU-4:

Equipment	Facility Designation
Coal Unloading Facility	CUF
Twelve coal conveyors	Conveyors 1-5, 6A, 6B, 7, 11, 12, 21, & 22
One bucket-wheel stacker-reclaimer	Stacker-reclaimer
Coal blending system	
Chemical stabilizing dust suppression systems at CUF and No. 5 reclaim	(N/A)
Four coal silos	Silos 21-28 (Unit 2)
Coal surge bin	(N/A)
Four bottom ash dewatering bins	Bins 11, 12, 21, 22
Various mobile machinery	(N/A)
Four fly ash bins	Bins 11, 12, 13, 14
Fly Ash Weigh Bin Baghouse	Same
FGD Bleed Treatment Lime Storage Silo	Same
Limestone Ball Mill	Same

Bin 11 – Unclassified ash with single UCC model 6050 pin paddle mixer/unloader – 330 tph capacity, installed in 2009

Bin 12 – Classified ash with single UCC model 6050 pin paddle mixer/unloader – 330 tph capacity, installed in 2009

Bin 13 – Repurposed as a boron removal clarifier in the FGD Bleed Treatment system

Bin 14 – Replaced into service in 2011 to handle fly ash from the Lodge-Cottrell that contains carbon sorbent from the mercury control system.

Coal Unloading Facility Details

The Coal Unloading Facility consists of two below-grade hoppers, each associated with a drag flight conveyor that transfers coal to an interim conveyor that feeds the new radial stacker or feeds directly into the coal blending system. The radial stacker transfers coal to the plant stockpiles. Coal in the coal stockpiles is dozed to the coal blending/plant feed conveyors. The following transfer points are associated with the Coal Unloading Facility:

1. Rail car to below-grade hoppers (2)
2. Below-grade hoppers to apron feeders
3. Apron feeders to Conveyor 8A
4. Conveyor 8A to Conveyor 8B (stacker)
5. Conveyor 8B (stacker) to coal stockpile or Conveyor 8C
6. Conveyor 8C to ground level reclaims 3, 3A

7. Reclaims 3, 3A to Conveyor 4 or 4A (which feed the plant)

The maximum coal unloading rate is 4,000 tons per hour with 5,000 ton per hour surge capacity. The Coal Unloading Facility began operation on February 1, 2008.

FGD Bleed Treatment Lime Storage Silo Details

The FGD Bleed Treatment Lime Storage Silo stores hydrated lime ($Ca(OH)_2$). The lime is used to treat a bleed stream of scrubber liquid from the flue gas desulfurization system. The scrubber liquid treatment system is designed to reduce boron and zinc levels in the wastewater. The silo is located immediately southeast of the Unit 1 scrubber vessel. The silo is pneumatically loaded from trucks at a rate of approximately 16.7 tons per hour. Specific silo and associated dust collector information is listed below.

Silo Make/Model:	USFilter Lime Silo; WHM® Bulk Chemical Storage; Model T-1
Silo Capacity:	5,600 cubic feet
Silo Height:	53'1" without dust collector, 58' with dust collector
Dust Collector Make/Model:	C.P. Environmental Filters, Inc. / model 36-CTBFD-009-CM-30
Number of Bags:	9 cartridge style pleated "bags" measuring 6" in diameter by 36" l long
Cleaning Method:	Reverse Pulse-Jet
Cloth Area:	270 ft^2
Filter Media:	8.5 oz. pleated spun bonded polyester felt with PTFE membrane laminated to the exterior surface of the fabric
Design Exhaust Flow:	600 acfm
Installed:	2006

The manufacturer warrants that the particulate matter concentration in the effluent gas will not exceed an average of 0.005 gr/acf based on an inlet loading of 10 gr/acf.

Limestone Ball Mill Details

The Limestone Ball Mill is located in the ground floor of the FGD Building. The Limestone Ball Mill crushes limestone transferred from the limestone storage silo with water to form a limestone slurry for use in the Flue Gas Desulfurization systems. The Limestone Ball Mill is fully enclosed and is not a potential source of particulate matter emissions (the process is fully enclosed and water is injected at the upstream end of the ball mill), however it is an "affected facility" for the purposes of Title 40 Code of Federal Regulations (CFR) Part 60 Subpart OOO "Standards of Performance for Nonmetallic Mineral Processing Plants."

Ball mill processing capacity:	41 tons per hour
Manufacturer:	Svedala Industries (now known as Metso Minerals)
Serial number:	49663
Manufacture date:	May 2000
Installation date:	September 2001

Fly Ash Weigh Bin Baghouse Details

The Fly Ash Weigh Bin receives fly ash from the No. 11 Air Slide and the No. 12 Air Slide. The Fly Ash Weigh Bin was manufactured by Halliburton and has a capacity of up to 30,000 pounds. During normal operation, approximately 900 cfm of fluidizing air from one of the air slides is vented out of the Fly Ash Weigh Bin Baghouse. The Fly Ash Weigh Bin Baghouse draws approximately 900 cfm of air from the fly ash loading spout to control fugitive dust while loading, for a total air flow of 1,800 cfm. At times total airflow could range up to 2,700 cfm if fly ash were being loaded into the Fly Ash Weigh Bin from both air slides (i.e. more than one Fly Ash Bin) simultaneously. The Fly Ash Weigh Bin Baghouse is turned on/off by the contractor in charge of loading fly ash (currently Lafarge North America), however TransAlta will retain responsibility for maintenance of, and the emissions from, the Fly Ash Weigh Bin Baghouse. The following details of the cartridge collector were provided:

Baghouse Make / Model:	Donaldson Torit / Powercore CPV-4
Installed:	Installation completed July 30, 2012
Design Flow Rate:	2,700 cfm (rated at 1,400 cfm to 2,700 cfm)
Filter Description:	4 cartridges (7" wide x 22" long x 7.5" tall), total of 252 ft^2 filter area
Filter Description:	Ultra-web nanofiber material
Cleaning Method:	Pulsed jet – collected fly ash will drop down into the fly ash weigh bin.
Stack Description:	16" inside diameter stack exhausting vertically approximately 8' above the top of the fly ash weigh bin and 49-50' above ground level. An 18" diameter shroud (stack within a stack design) may be used to prevent rain intrusion into the stack.

Applicable NSPS/NESHAP/MACT: None

CAM Applicability Review

Particulate matter is the only regulated pollutant of interest for units that comprise EU-4. Equipment that utilizes a control device and has a particulate matter emission limit is reviewed below.

Equipment	Uncontrolled PTE (tons)	Subject to CAM?
FGD Bleed Treatment Lime Storage Silo	12[1]	No
Fly Ash Bin 11	0[2]	No. CAM plan is included in the Permit as M31 for the exhausts (treated as separated EUs from the piping, storage, and transfer equipment listed here).
Fly Ash Bin 12		
Fly Ash Bin 14		
Fly Ash Weigh Bin	68[3]	No

[1] Assumes an inlet loading of 10 gr/dscf (likely a gross overestimate) for a potential operating time of 467 hours per year based on 6 25-ton loads per week at an off-loading rate of 16.7 tons per hour. Note that the bin vent may be "inherent process equipment".

[2] This does not include the baghouses which are treated as separate EUs. This equipment consists only of sealed piping and transfer equipment which does not have emissions unless a pipe fails or leaks.
[3] Assumes 1,800 cfm of operation for 8,760 hours per year at an "uncontrolled" rate of 1 gr/dscf. Due to the nature of fly ash, filtration of some time is required, therefore at least some level of control is "inherent process equipment". Unit operates with 900 cfm of bin fluidizing air at all times, only exceeding this rate when actual loading is occurring and when the weigh bin is receiving ash from more than one storage bin at a time.

EU-5 Turbine Lube Oil Mist Vent 1 (Retired)

Retired at the end of 2020.

EU-6 Turbine Lube Oil Mist Vent 2

The Unit 2 turbine is equipped with an oil storage tank, lube oil reservoir, and other components of the lube oil system that supplies clean oil to the turbine-generator bearings and other equipment. The turbine lube oil mist eliminator controls oil droplet emissions from the vapor extractor, which removes moisture from the oil.

Turbine Lube Oil Mist Eliminator 2 is an Advanced Environmental Systems Air-Clear™ Mist Collection System sized to handle up to 1,000 cubic feet per minute (cfm) of oil mist at a concentration of 1,500 mg/m^3 and a temperature of 120°F. The mist eliminator utilizes 67 ft^2 (based on the inside diameter of cylindrical filters) of fiberbed diffusion coalescing filters to collect up to 99.5% of the liquid mists on a particle count basis. Manufacturer literature suggests that the collection efficiency can be as high as 99.99% on a mass basis. This unit is designed to maintain the exit opacity at 5% or below. The blower system is designed to supply an average exhaust flowrate of 5 cfm (maximum of 600 cfm for short periods). This is substantially lower than the 1,000 cfm design of the mist eliminator. The mist eliminator is designed so that the filter elements are replaced when the gas flow becomes overly restricted due to high differential pressure across the filters. The differential pressure across the filters is less important to emission control than the average flow velocity through the filters. The manufacturer estimates that a velocity of 40 feet per minute or less is required for adequate opacity control. The permittee's blower has the capacity to produce a velocity of approximately 9 feet per minute (600 cfm/67 ft^2).

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
VOC	0.01	Yes	Yes	No

EU-7 Black Stop Diesel Generator Engine (Retired)

The Black Stop Diesel Generator Engine retired at the end of 2020.

EU-8 Journal Shop Welding

Coal journals used in the coal pulverizers are repaired in the Journal Shop. Repairs consist primarily of welding replacement metal onto the journals to replace metal worn off during normal use. TransAlta submitted Air Discharge Permit Application L-613 on February 4, 2008 for replacement of the existing 1,800 cfm cartridge-style Torit baghouse with a larger Donald Torit cartridge style baghouse rated at 4,000 cfm. The purpose of the replacement was to improve worker hygiene in the Journal Shop, especially to reduce potential worker exposure to chromium welding fumes.

Journal Shop – Baghouse. Journal Shop welding electrode use is less than 12,000 pounds per year. The baghouse pickups are positioned in such a way to minimize exposure of welders to welding fumes. Most welding is expected to be shielded metal arc welding. The following baghouse details were available:

Make / Model:	Donaldson Torit / DFO 2-8
Filter Area:	1,520 square feet of cartridge style filters
Primary Filter Media:	Ultra-Web FR with a MERV rating of 13
No. of Filters:	8
Secondary Filters:	Contains two 24" x 24" x 12" HEPA filters downstream of cartridge filters
Design Capacity:	4,000 cubic feet per minute @ 10" w.c., 70 °F
Installed:	September 10, 2008
Stack Description:	Exhausts horizontally through two 24" x 24" x 12" ducts at ambient temperature ~12' above grade.

Applicable NSPS/NESHAP/MACT: None

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	0.49	Yes	Yes – opacity as a surrogate for PM	No

EU-9 Emergency Diesel Generator 1

Engine Rating:	440 horsepower
Engine Make / Model:	Caterpillar / D343
Engine Serial Number:	6287637
Stack Description:	~ 8" diameter exhausted above the 8th floor roof

Diesel fuel oil is burned by this generator to supply back-up power to critical electrical systems in Unit 1. The generator is operated for about ¼ hour each week for testing, and consumes less than 300 gallons of fuel annually producing emissions below the thresholds of WAC 173-401-530(4) for an insignificant emission unit. This unit is not an insignificant emission unit because it is subject to applicable requirements found in 40 CFR 63 Subpart ZZZZ. The applicable requirements became effective May 3, 2010 (Federal Register notice dated March 3, 2010) with a compliance date of May 3, 2013.

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart ZZZZ

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	1.36	No	No	No
CO	0.29	No	No	No
VOC	0.11	No	No	No
SO_2	0.00048	No	No	No
PM_{10}	0.01	No	No	No

EU-10 Emergency Diesel Generator 2

Generator Set Make / Model: Caterpillar / C9
Generator Output: 300 kW
Engine Make / Model: Caterpillar / C9
Engine Serial Number: CASP01214
Fuel: Diesel, 22.7 gallons per hour at full load
Engine Power: 480 hp
Engine Built: 2016
Engine Certification: EPA Tier 3 Emergency
Stack Description: ~ 7" diameter, exhausting vertically, ~8' above the 8th floor roof, stack flow 2,460.9 acfm at 927.2°F
Location: 46°45'19.19"N, 122°51'36.24"W
NSPS/NESHAP/MACT: 40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ

Applicable NSPS/NESHAP/MACT: 40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	0.42	No	No	No
CO	0.02	No	No	No
VOC	0.01	No	No	No
SO_2	0.00049	No	No	No
PM_{10}	0.0024	No	No	No

EU-11 Fire Pump Engine

The Fire Pump Engine drives a backup fire water pump. This unit will operate for testing and maintenance of the engine, as necessary during an emergency, and for limited time periods for non-emergency operation (e.g. during maintenance events when the electrical pump system is unavailable). Total annual operation is expected to be no more than 504 hours per year (3 weeks). Engine details are provided below:

Engine Make / Model: Cummins / CFP7E-F50 Fire Pump Driver
Engine Serial Number: 73467344
Fuel: Diesel, 10.6 gallons per hour at full load
Engine Power: 205 hp
Engine Built: 2012
Engine Installed: Installation completed December 27, 2012
Engine Certification: EPA Tier 3
Stack Description: ~ 4" diameter, exhausting vertically ~18' above grade, 1' 10" above roof level, stack flow 1,174 acfm @ 879°F
Location: 46°45'22.44"N, 122°51'44.23"W

Applicable NSPS/NESHAP/MACT: 40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	0.28	No	Yes	No
CO	0.14	No	Yes	No
VOC	0.01	No	No	No
SO_2	0.0006	No	No	No
PM_{10}	0.013	No	Yes	No

EU-12 Coal Unloading Facility Emergency Diesel Sump Pump Engine

The CUF Emergency Diesel Sump Pump consists of a Godwin water pump driven by a diesel engine. The engine is operated for testing, maintenance, and as an emergency backup to the existing electric water pump. Engine details are provided below:

Engine Make / Model: John Deere / 4045TF275
Engine Serial Number: PE 4045TF593425
Engine Family: 6JDXL06.8082
Fuel: Diesel, 42.7 pounds per hour @ full load
Horsepower Rating: 115
Engine Built: July 9, 2006
Engine Certification: EPA Tier 2
Stack Description: ~ 4" diameter, exhausting vertically ~6.5' above grade, stack flow 713 acfm @ 860 °F

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart ZZZZ, 40 CFR 60 Subpart IIII

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	0.25	No	Yes	No
CO	0.04	No	Yes	No
VOC	0.0077	No	No	No
SO_2	0.00013	No	No	No
PM_{10}	0.0055	No	Yes	No

EU-13 SEA System 1

Based on a review of the potential Sorbent Enhancement Additive (SEA) materials, no significant increase in pollutant emission rates is expected as a result of injecting SEA into the boiler. Emissions are associated with venting of SEA laden air from the SEA hopper and the hammermill crusher through the SEA System 1 Cartridge Collector. The system feed capacity is 5-100 lb/hr, therefore the hammermill crusher is not subject to 40 CFR 60 Subpart OOO. The following details of the cartridge collector were provided:

Make / Model:	Grünergy Technologies / PV-2-160 AR III
Design Flow Rate:	1,130 cfm
Design Exhaust Concentration:	0.005 gr/dscf
No. of Cartridges:	2
Filter Description:	160 ft^2 of 8 oz/yd^2 thermally fused polyester with PTFE membrane
Cleaning Method:	Pulsed jet
Stack Description:	6" diameter stack exhausting vertically on east wall of the boiler building.

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	42.42[1]	Yes	Yes	No

[1] Assumes conservative (high) inlet concentration loading of 1.0 gr/dscf.

EU-14 SEA System 2

Based on a review of the potential SEA materials, no significant increase in pollutant emission rates is expected as a result of injecting SEA into the boiler. Emissions are associated with venting of SEA laden air from the SEA hopper and the hammermill crusher through the SEA System 2 Cartridge Collector. The system feed capacity is 5-100 lb/hr, therefore the hammermill crusher is not subject to 40 CFR 60 Subpart OOO. The following details of the cartridge collector were provided:

Make / Model:	Grünergy Technologies / PV-2-160 AR III
Design Flow Rate:	1,130 cfm
Design Exhaust Concentration:	0.005 gr/dscf
No. of Cartridges:	2
	Filter Description: 160 ft^2 of 8 oz/yd^2 thermally fused polyester with PTFE membrane
Cleaning Method:	Pulsed jet
Stack Description:	6" diameter stack exhausting vertically on east wall of the boiler building.

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	42.42[1]	Yes	Yes	No

[1] Assumes conservative (high) inlet concentration loading of 1.0 gr/dscf.

EU-15 Sorbent Silo 1

Sorbent Silo 1 is located directly north of the ductwork between the Koppers ESPs and the Lodge-Cottrell ESPs. The following details of the vent filter system were provided:

Make / Model:	Torit Technologies / TBV-4 Insertable
Design Flow Rate:	350 cfm, passively vented
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	4 Ultra-Web II NL cartridges, each containing a filter area of 170 ft^2 of 8 oz/yd^2 nanofiber on cellulose material
Cleaning Method:	Reverse air jet
Stack Description:	Circular exhaust measuring approximately 12" diameter exhausting vertically on the top of the silo, approximately 95' above grade

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	13.14[1]	Yes	Yes	No

[1] Assumes conservative (high) inlet concentration loading of 1.0 gr/dscf.

EU-16 Sorbent Silo 2

Sorbent Silo 2 is located directly south of the ductwork between the Koppers ESPs and the Lodge-Cottrell ESPs. The following equipment details were provided:

Make / Model:	Torit Technologies / TBV-4 Insertable
Design Flow Rate:	350 cfm, passively vented
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	4 Ultra-Web II NL cartridges, each containing a filter

	area of 170 ft^2 of 8 oz/yd^2 nanofiber on cellulose material
Cleaning Method:	Reverse air jet
Stack Description:	Circular exhaust measuring approximately 12" diameter exhausting vertically on the top of the silo, approximately 95' above grade

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	13.14[1]	Yes	Yes	No

[1] Assumes conservative (high) inlet concentration loading of 1.0 gr/dscf.

EU-17 Fly Ash Bin 11 Baghouse

The Fly Ash Bin 11 Baghouse is located on top of the fly ash bins. A baghouse leak detector has been installed. The following equipment details were provided:

Make / Model:	Industrial Accessories Company (IAC) / 144TB-BVWT-256-S6
Design Flow Rate:	14,730 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	256 bags, 114 inches long with a total filter area of 4,997 ft^2, top load, DuPont Type 54 or equal, polyester material.
Cleaning Method:	Reverse air jet
Stack Description:	Rectangular exhaust measuring approximately 18" x 50" exhausting vertically ~ 5' above the top of the baghouse, approximately 30' above the top of the fly ash bin.
Leak Detector:	Tribo-Flow model 4001-1111-0I-154N with 12" long probe

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	553[1]	Yes	Yes	Yes – CAM plan is included in the Permit as M31.

[1] Assumes inlet concentration loading of 1.0 gr/dscf.

EU-18 Fly Ash Bin 12 Baghouse

The Fly Ash Bin 12 Baghouse is located on top of the fly ash bins. A baghouse leak detector has been installed. The following equipment details were provided:

Make / Model:	Industrial Accessories Company (IAC) / 144TB-

	BVWT-256-S6
Design Flow Rate:	14,730 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	256 bags, 114 inches long with a total filter area of 4,997 ft^2, top load, DuPont Type 54 or equal, polyester material.
Cleaning Method:	Reverse air jet
Stack Description:	Rectangular exhaust measuring approximately 18" x 50" exhausting vertically ~ 5' above the top of the baghouse, approximately 30' above the top of the fly ash bin.
Leak Detector:	Tribo-Flow model 4001-111-I-154N with 12" long probe

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	553[1]	Yes	Yes	Yes – CAM plan is included in the Permit as M31.

EU-19 Fly Ash Bin 14 Baghouse

The Fly Ash Bin 14 Baghouse is located on top of the fly ash bins. A baghouse leak detector has been installed. The following equipment details were provided:

Make / Model:	Industrial Accessories Company (IAC) / 144TB-BVWT-256-S6
Design Flow Rate:	14,730 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	256 bags, 114 inches long with a total filter area of 4,997 ft^2, top load, DuPont Type 54 or equal, polyester material.
Cleaning Method:	Reverse air jet
Stack Description:	Rectangular exhaust measuring approximately 18" x 50" exhausting vertically ~ 5' above the top of the baghouse, approximately 30' above the top of the fly ash bin.
Leak Detector:	Tribo-Flow model 4001-111-I-154N with 12" long probe

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	553[1]	Yes	Yes	Yes – CAM plan is included in the Permit as M31.

EU-20 Fly Ash Bin 14 Air Slide to Bin 11 Air Slide

The air slide utilizes approximately 900 cfm of air to help move fly ash from Fly Ash Bin 14 to the Bin 11 Air Slide which in turn moves fly ash to the weigh hopper. The air is exhausted through a cartridge-style air filter system. The blower is located downstream of the air filter. The following equipment details were provided:

Make / Model:	DCL / VML185
Design Flow Rate:	900 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	4 polyester cartridges, each measuring approximately 8" outside diameter by 22 inches long, combined filter area of 185 ft^2
Cleaning Method:	Reverse air jet
Stack Description:	Exhausts approximately 35 feet above ground on the south side of the Bin 11 building – discharged vertically through ~ 6" diameter exhaust.

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	33.8	Yes	Yes	No

EU-21 Fly Ash Bin 14 to 6050 Air Slide

The air slide utilizes approximately 600 cfm of air to help move fly ash from Fly Ash Bin 14 to the 6050 unloader. The air is exhausted through a cartridge-style air filter system. The blower is located downstream of the air filter. The following equipment details were provided:

Make / Model:	DCL / VML140
Design Flow Rate:	600 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	3 polyester cartridges, each measuring approximately 8" outside diameter by 22 inches long, combined filter area of 140 ft^2
Cleaning Method:	Reverse air jet
Stack Description:	Exhausts approximately 35 feet above ground in between the Bin 11 and Bin 14 buildings discharged vertically through ~ 6" diameter exhaust.

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	33.8	Yes	Yes	No

EU-22 Fine Coal Handling

EU-22 was retired effective June 30, 2021.

Insignificant Emission Units

IEU-55B Maintenance Shops Welding Emissions

Maintenance welding is exempt from registration according to SWCAA 400-101(10) and did not require an approval. Emissions from this discharge point are less than 0.1 ton/yr, well below the 0.75 ton PM_{10}/yr threshold of WAC 173-401-530(4)(e) so this unit is considered insignificant. Based on a conservative estimate that no more than 2,000 lb of electrode is used annually in any one shop and the highest value emission factor of 82 lb/1,000 lb from EPA AP-42 Table 12.19-1, the annual emissions are calculated to be:

2,000 lb * (82 lb/1,000 lb) * (1 ton/2,000 lb) < 0.1 ton/yr

IEU-57 Cooling Towers

Primary cooling of the process steam takes place at the cooling towers for the Coal Plant. The cooling towers are categorically exempt insignificant emissions units under WAC 173-401-532(121) because of processing exclusively non-contact cooling water. Furthermore, the cooling towers do not use chromium-based water treatment chemicals. Sodium hypochlorite is used to treat circulating cooling water and does not escape to the ambient air.

IEU-61 Cold Solvent Parts Washers

Eight parts washing solvent tanks are used at the Centralia Plant site for only non-chlorinated solvent, each tank ranging in size from 30 to 40 gallons. The tanks are covered by lids when parts are not actively loaded or unloaded into or out of the tanks. The parts washers emit minimal VOC emissions and are considered insignificant because only fugitive emissions are released consistent with the definition of insignificant emission units in WAC 173-401-530(1)(d) and because their emissions are below the 2.0 tons per year VOC threshold of WAC 173-401-530(4)(d). Based on solvent use of 12,000 lb/yr and a recycle rate of 92% estimated by the solvent recycle vendor, VOC emissions are calculated to be:

12,000 lb/yr * (1 - 0.92) * (1 ton/2,000 lb) = 0.48 tons per year VOC

IEU-71 Fuel Oil Storage Tank 1

This storage tank supplies fuel oil to the boiler for startups and has a capacity of 100,000 gallons. Its VOC emissions are well below the insignificant emission thresholds of WAC 173-401-530(4)(d) (2.0 tons per year of VOC) so the emission unit is considered insignificant. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.079 lb/1,000 gal was derived for this tank. For annual throughput of 220,000 gallons, VOC emissions are calculated to be:

220,000 gal * 0.079 lb/1,000 gal * (1 ton/2,000 lb) = 0.009 tons per year VOC

IEU-72 Fuel Oil Storage Tank 2

This storage tank supplies fuel oil to the boiler for startups and has a capacity of 100,000 gallons. Its VOC emissions are well below the insignificant emission thresholds of WAC 173-401-530(4)(d) (2.0 tons per year of VOC) so the emission unit is considered insignificant. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.079 lb/1,000 gal was derived for this tank. For an annual throughput of 220,000 gallons, VOC emissions are calculated to be:

220,000 gal * 0.079 lb/1,000 gal * (1 ton/2,000 lb) = 0.009 tons per year VOC

IEU-73 Gasoline Storage Tank

The tank is a 5,200 gallon above ground tank with a white concrete shell used to fuel vehicles and equipment on site. The tank utilizes submerged fill and is not equipped with Stage I or II vapor recovery. No pressure/vacuum valve is utilized. Annual emissions from the storage tank are reported by the permittee to be less than 0.5 ton/yr, well below the 2.0 tons VOC/yr insignificant emission threshold of WAC 173-401-530(4)(d).

Gasoline vapors are emitted primarily from the following:
1. Storage Tank Loading Losses
2. Storage Tank Breathing Losses

Storage tank loading and breathing losses were estimated using EPA's Tanks 4.09D emission estimation software.

<u>The parameters were used in Tanks 4.09D:</u>

Nearest City:	Olympia, WA
Type of Tank:	Horizontal Tank
Shell Length:	12.5'
Shell Diameter:	9'
Tank Volume:	5,200 gallons
Shell Color:	White
Shell Condition:	Poor
Vacuum Setting:	0.0 psi
Pressure Setting:	0.0 psi
Liquid:	Gasoline (RVP=10)

Based on EPA Speciate 3.2 profile number 2455, approximately 50.85% of the total VOC emissions are toxic air pollutants (TAPs) as defined by WAC 173-460, and approximately 12.91% of the total VOC emissions are federally listed hazardous air pollutants (HAPs). For a throughput of 930,000 gallons per year, TAP and HAP emission rates are estimated to be:

IEU-73 Gasoline Storage Tank Emissions

Throughput =	15,000	gallons per year
Control Efficiency =	0%	(Assume no vapor balance fittings)
Emission Factors		
Storage Tank Working Losses =	7.099	lb/1,000 gallons
Storage Tank Breathing Losses =	770	lbs/year

Emissions Summary	lbs	tons
Volatile Organic Compounds	876	0.44
Toxic Air Pollutants	446	0.22
Hazardous Air Pollutants	113	0.06

IEU-74 Diesel Storage Tank

The storage tank has a capacity of 5,200 gallons and is used to fuel vehicles and equipment on site. VOC storage tanks not greater than 10,000 gallons capacity with appropriate closure and vapor pressure not greater than 80 mmHg are defined in WAC 173-401-533(2)(c) to be insignificant emission units. Annual emissions from the storage tank are reported by the permittee to be less than 0.001 ton/yr, below the 2.0 tons VOC/yr insignificant emission threshold of WAC 173-401-530(4)(d). Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.020 lb/1000 gal was derived for this tank. For an annual throughput of 16,000 gallons, VOC emissions are calculated to be:

16,000 gal * 0.020 lb/1000 gal * (1 ton/2,000 lb) = 0.0002 tons per year VOC

IEU-75 U1 Emergency Diesel Generator Fuel Storage Tank

This fuel storage tank has a capacity of 350 gallons and supplies the U1 emergency diesel generator. Storage tanks not greater than 1,100 gallons capacity with maximum vapor pressure of 550 mmHg are defined in WAC 173-401-533(2)(b) to be insignificant emission units. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.034 lb/1,000 gal was derived for this tank. For an annual throughput of 300 gallons, VOC emissions are calculated to be:

300 gal * 0.034 lb/1,000 gal * (1 ton/2,000 lb) = 0.00001 tons per year VOC

IEU-76 U2 Emergency Diesel Generator Fuel Storage Tank

This fuel storage tank has a capacity of 350 gallons and supplies the U2 emergency diesel generator. Storage tanks not greater than 1,100 gallons capacity with maximum vapor pressure of 550 mmHg are defined in WAC 173-401-533(2)(b) to be insignificant emission units. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.034 lb/1,000 gal was derived for this tank. For annual throughput of 300 gallons, VOC emissions are calculated to be:

300 gal * 0.034 lb/1,000 gal * (1 ton/2,000 lb) = 0.00001 tons per year VOC

IEU-77 Emergency Diesel Fire Pump Fuel Storage Tank

This fuel storage tank has a capacity of 350 gallons and supplies the emergency diesel fire pump. Storage tanks not greater than 1,100 gallons capacity with maximum vapor pressure of 550 mmHg are defined in WAC 173-401-533(2)(b) to be insignificant emission units. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.47 lb/1,000 gal was derived for this tank. For an annual throughput of 150 gallons, VOC emissions are calculated to be:

150 gal * 0.47 lb/1,000 gal * (1 ton/2,000 lb) = 0.00004 tons per year VOC

IEU-78 Limestone Silo

The limestone silo receives limestone shipments from trucks and feeds the ball mill for the FGD system. Particulate matter emissions are controlled by a Flex-Kleen model 30/36-PVBL-9-11 G vent filter (serial number 100770) located on top of the limestone silo. The vent filter has a rated efficiency of 99.9%. The conveyor to the silo has a capacity of 200 tons per hour and the ball mill has a capacity of 41 tons per hour, therefore the unit can operate up to 8,760*(41/200) = 1,796 hours per year. The vent filter fan is rated at 900 cfm. At a maximum emission concentration of 0.005 gr/dscf (typical maximum for material handling silo filters), potential emissions are:

$$\frac{1{,}796 \text{ hours per year}}{\text{year}} * \frac{900 \text{ cubic feet}}{\text{minute}} * \frac{60 \text{ minutes}}{\text{hour}} * \frac{0.005 \text{ grains}}{\text{standard cu ft}} * \frac{1 \text{ pound}}{7{,}000 \text{ grains}} = \frac{69 \text{ pounds}}{\text{year}}$$

Emissions from this discharge point are well below the 0.75 ton PM_{10}/yr threshold of WAC 173-401-530(4)(e) so this unit is considered insignificant.

IEU-79 Lime Silo

The lime silo receives lime shipments from trucks and feeds the FGD system when necessary (e.g. ball mill is inoperable). Particulate matter emissions are controlled by a Flex-Kleen model 30-PVBL-9-11 G vent filter located on top of the limestone silo. The vent filter has a rated efficiency of 99.9%. This unit can receive approximately 25 tons per hour of material from a truck (1 truckload per hour). The vent filter fan is rated at 900 cfm. At a maximum emission concentration of 0.005 gr/dscf (typical maximum for material handling silo filters), potential emissions are:

$$\frac{8{,}760 \text{ hours per year}}{\text{year}} * \frac{900 \text{ cubic feet}}{\text{minute}} * \frac{60 \text{ minutes}}{\text{hour}} * \frac{0.005 \text{ grains}}{\text{standard cu ft}} * \frac{1 \text{ pound}}{7{,}000 \text{ grains}} = \frac{338 \text{ pounds}}{\text{year}}$$

This unit typically operates one hour per day, so typical emissions are far less than 338 pounds per year. Emissions from this discharge point are well below the 0.75 ton PM_{10}/yr threshold of WAC 173-401-530(4)(e) so this unit is considered insignificant.

Nonroad Engines

Jetstream Pressure Washer Engine. The engine is used to drive a Jetstream pressure washer to clean industrial equipment at the power plant and associated facilities. Equipment details are listed below.

Location:	Variable at TransAlta Centralia Generation, Centralia, WA
Engine Make / Model:	John Deere / 6068HF485 PowerTech Plus Diesel Engine
Fuel:	Diesel
Fuel Consumption:	11.8 gallons per hour (based on John Deere literature showing 0.34 lb/hp-hr fuel consumption)
Horsepower Rating:	251 bhp (intermittent)
Installed:	~2009
Engine Built:	2008 model year
Engine Certification:	EPA Tier 3
Stack Description:	Oriented vertically, ~3.75" inside diameter
Applicable Federal Regulations:	40 CFR 89 (nonroad)

Pump-05 Engine. Pump-05 (at one time referred to as "Pump 8") consists of a Godwin CD225M water pump driven by a diesel engine. Pump-05 is intended to be used primarily to support year-round maintenance activities at a variety of plant locations. Engine details are provided below:

Engine Make / Model:	John Deere / 4045TF275
Engine Serial Number:	PE4045T246562
Engine Family:	2JDXL06.8014
Fuel:	Diesel, 5.8 gallons per hour at full load
Engine Power:	115 hp (86 kW)
Engine Built:	December 12, 2002
Engine Certification:	EPA Tier 1
Stack Description:	~ 4" diameter, exhausting vertically ~6.5' above grade, stack flow 623 acfm at 833°F
Primary Location:	None established
Applicable Federal Regulations:	40 CFR 89 (nonroad)

Pump-07 Engine. Pump-07 consists of a Godwin CD225M water pump driven by a diesel engine. Pump-07 is intended to be used primarily to support year-round maintenance activities at a variety of plant locations. Engine details are provided below:

Engine Make / Model:	John Deere / 4045TF285
Engine Serial Number:	PE4045L276859
Engine Family:	BJDXL04.5144
Fuel:	Diesel, 41 lb/hr at full load (5.7 gallons per hour)
Engine Power:	99 bhp, 74kW at 2,400 rpm
Engine Built:	July 7, 2015
Engine Certification:	EPA Tier 3 – Engine tag indicates that this engine complies with EPA emission control standards

	through 40 CFR 1039.625. This is the "Transition Program for Equipment Manufacturers". Otherwise this model year engine would need to be certified to Tier 4 standards.
Stack Description:	~ 4" diameter, exhausting vertically ~6.5' above grade, stack flow 623 acfm at 833°F
Primary Location:	None established
Applicable Federal Regulations:	40 CFR 1039 (nonroad)

C. Observations During Inspection:

Observations are primarily described in the paragraphs below and in the "observations" column of the following tables. The physical inspection was primarily conducted on October 23, 2025, and November 4, 2025, although observations from visits during source emission testing on various dates are also included in this inspection report.

Abraham Apfel and I arrived at the facility at approximately 9:25 a.m. on October 23, 2025, for an unannounced inspection. Before entering the facility, we drove past the facility on Big Hanaford Road. At this time we observed visible emissions from the Fly Ash Unloading Baghouse and took a photo and short video from Big Hanaford road to the east of the baghouse. Visible emissions were clearly above 20% opacity.

We proceeded to the facility and met with Mr. Sam Bocook who escorted us throughout the inspection.

We first visited the Fly Ash Unloading Baghouse and found the unit operating with significant visible emissions while no trucks were being loaded. Mr. Bocook asked the operators to turn off the baghouse system since no trucks were being loaded and have maintenance check out the baghouse. When I returned for a follow-up inspection on November 4, 2025, the unit was operating without any visible emissions. Mr. Bocook and I met with maintenance personnel who informed us that they had simply changed the filters because they were "plugged" but didn't see any improper seating or holes in the old (dirty) filters. This "baghouse" uses a cartridge-style filter system and since the unit was structurally intact, a filter or gasket failure or improper seating of the filters is the only likely causes of excess emissions. Operation of the unit in this manner caused an exceedance of the permitted opacity limit and was a violation of SWCAA 400-116 "Maintenance of Equipment". NOV 10642 was issued for this violation.

During this first day of the inspection Unit #2 was operating at 672 MW (gross). All CEMS indicated compliance with the permitted emission limits.

Recirculation pumps 21 and 23 were operating on the FGD scrubber (levels 3 and 4 sprays in the scrubber).

Fly ash bins 11 and 12 were in use, both with a pressure drop of approximately 3" w.c. Fly ash bin 14 remains out of service. I did not see any evidence of current or recent ash leaks.

A few small fires were smoldering in the coal pile, which is normal. No trains were unloading coal during the inspection.

D. Reporting/Records Review:
Quarterly reports, source test reports, startup, shutdown, upset, and Acid Rain Reports were reviewed, and the reviews are documented in the semi-annual reports reviews. Reports covering the period of July 2024 to June 2025 were reviewed in a semi-annual review reports dated November 29, 2025.

Substitute House Bill 1257 (HSB 1257) Milestones
A result/outcome of the (RACT process) Centralia Collaborative Decision Making Group (CDM) was HSB 1257. The CDM group reviewed several proposals for emission reductions and the realistic options that resulted were the closure of the plant and mine with the loss of nearly 670 jobs, the closure of the mine with the loss of nearly 510 jobs, or installation of two scrubbers. The least costly option for the owners was the closure of the facility. In addition to maximizing the reduction of Centralia plant SO_2 emissions, the CDM group was interested in preserving jobs and the local economy. Therefore, changes in the tax law seemed to be the most practical solution in reducing the funding gap between the two options and provided the owners the resource assistance to choose the CDM target solution – to keep the plant open and utilize the two-scrubber option. HSB 1257 (codified in RCW 82.08.811 and RCW 82.12.811) is a Washington state law that provides tax exemptions for coal sales to thermal electric generation facilities (in operation after 12/31/69 and before 7/1/75) in order to update their pollution control equipment and therefore continue to play a long-term vital economic role in the community. In order for the Centralia Plant to obtain their tax credits, certain milestones had to be demonstrated. Currently the only active requirement is for SWCAA to notify the Department of Ecology, who will in turn notify the Department of Revenue of any violation of the 10,000 tpy limit.

HSB 1257 – Project Milestones	**Notice/Notes**
Certification of reasonable initial progress	SWCAA 5/26/99 letter to Dept. of Revenue certifying reasonable initial progress
Certification of continued progress	SWCAA 5/26/99, 2/1/00, 2/1/01, 2/14/02 letters to Dept. of Revenue certifying continued progress.
Initial 10,000 tons SO_2 certification	SWCAA certified on April 28, 2003 that TransAlta met the 10,000 tpy limit beginning the period 4/1/02-3/31/03.
Notification of any violation of 10,000 tons SO_2 to be made immediately	No violation has occurred.

E. Annual Emissions:
My review of the emissions inventory is detailed in a report dated May 21, 2025.

F. Compliance Assessment with Applicable Requirements/Emission Limits:

New Source Performance Standards.

Title 40 CFR Part 60.670 et seq. (Subpart OOO) "Standards of Performance for Nonmetallic Mineral Processing Plants" establishes particulate matter and opacity limitations and initial testing requirements for applicable units. The limestone ball mill is an applicable unit because it was built after August 31, 1983 (installed new ~2001), is a fixed unit with a capacity of greater than 25 tons per hour (the unit is rated at 40 tons per hour) and is used to reduce the size of limestone (a listed non-metallic mineral).

Title 40 Code of Federal Regulations (40 CFR) Part 60.4200 et seq. "Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines" requires that new diesel engines meet specific emission standards at the point of manufacture and during operation. In addition, maximum fuel sulfur contents are specified, and minimum maintenance standards are established. This regulation applies to the Fire Pump Engine, Coal Unloading Facility Emergency Diesel Sump Pump Engine, and the Unit #2 Emergency Diesel Generator Engine.

NESHAP/MACT Standards

Title 40 Code of Federal Regulations (CFR) 63.6580 et seq. (Subpart ZZZZ) "National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines" establishes national emission limitations and operating limitations for HAP emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. All of the stationary engines operated by TransAlta are affected sources under this regulation.

Title 40 CFR Part 63.7480 et seq. Subpart DDDDD "National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters" - Subpart DDDDD applies to industrial, commercial and institutional boilers and process heaters at major sources of HAP emissions. The regulation applies to the Auxiliary Boiler at the coal plant (EU-3). EU-3 is in the "Limited-use Boiler or Process Heater" subcategory because it burns liquid fuel and fuel consumption is limited to 600,000 gallons per year (~5.6% capacity factor) by SWCAA 97-2051R1. Any boiler or process heater that has a federally enforceable average annual capacity factor of no more than 10% is in the "Limited-use boiler or process heater" subcategory.

The effective date of the rule for existing boilers is January 31, 2016. TransAlta submitted an initial notification for EU-3 under the revised rules issued January 31, 2013, in a letter to EPA Region 10 and SWCAA dated May 1, 2013.

Title 40 CFR Part 63.9980 et seq. Subpart UUUUU "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units " - Subpart UUUUU applies to the two coal-fired boilers (EU-1 and EU-2). Subpart UUUUU establishes emission limits for non-Hg HAP metals, hydrogen chloride, and Hg, work practice standards, monitoring requirements and reporting requirements. TransAlta is in the subcategory of "Unit designed for coal greater than or equal to 8,300 Btu/lb" subcategory – listed as "Coal-fired unit not low rank virgin coal" in Table 2.

Regulatory Orders/Permits Since Last Inspection: None

All of the applicable requirements for TransAlta Centralia Generation are listed below in the format of Air Operating Permit SW98-8-R5-A.

Req. #	Generally Applicable Requirements	Emission Point	Inspector's Observations
Req-1	Permittee must not cause or permit any emission that exceeds 20% opacity for more than three minutes in any one hour. Reference Method: SWCAA Method 9 SWCAA 400-040(1)	Plantwide	As described elsewhere, visible emissions from the Fly Ash Unloading Baghouse exceeded this standard.
Req-2	Permittee must not cause or permit fallout of particulate matter beyond the source's property boundary in sufficient quantity to interfere unreasonably with the use and enjoyment of the property on which the fallout occurs. SWCAA 400-040(2)	Plantwide	I did not observe any evidence of fallout beyond the property boundary.
Req-3	Permittee must take reasonable precautions to prevent the release of fugitive emissions from any emission unit which is a source of fugitive emissions. SWCAA 400-040(3)	Plantwide	I did not observe any fugitive dust during the inspection.
Req-4	Permittee must use recognized good practice and procedures to reduce odors to a reasonable minimum. SWCAA 400-040(4) Local Only	Plantwide	I did not observe any significant odors during the inspection
Req-5	The Permittee must not cause or permit the emission of any air contaminant if it is detrimental to the health, safety, or welfare of any person, or causes damage to property or business. SWCAA 400-040(5)	Plantwide	I did not observe any detrimental emissions.

Req. #	Generally Applicable Requirements	Emission Point	Inspector's Observations
Req-6	Permittee must not cause or permit any emission unit to emit a gas containing sulfur dioxide in excess of 1,000 ppm of sulfur dioxide on a dry basis, corrected to 7% O_2 for combustion sources, and based on an average of 60 minutes. Reference Method: 40 CFR 60 Appendix A Methods 3A, 6C SWCAA 400-040(6) ADP 97-2057R1, Sections 22 and 28(a)	EU-2, EU-3, EU-9, EU-10, EU-11, EU-12	CEMS data has not indicated an exceedance in the past year. The sulfur content of the coal used at the facility during the past year (<0.5% S) is too low to cause an exceedance of this limit, even without emission controls. A sulfur content of ~1% could produce ~1,000 ppm SO_2 (uncontrolled).
Req-7	Permittee must not cause or permit the installation or use of any means which conceals or masks an emission which would otherwise violate any provisions of SWCAA 400-040. SWCAA 400-040(7)	Plantwide	No concealment or masking was observed during the inspection.
Req-8	Permittee must take reasonable precautions to prevent emissions of fugitive dust and operate the source to minimize emissions. SWCAA 400-040(8)(a)	Plantwide	I did not observe any fugitive dust during the inspection.
Req-9	Permittee must not cause or permit emissions of particulate matter from a combustion or incineration emission unit in excess of 0.1 gr/dscf of exhaust gas corrected to 7% oxygen. Reference Method: 40 CFR 60 Appendix A Method 5 SWCAA 400-050(1 and 4)	EU-2, EU-3, EU-9, EU-10, EU-11, EU-12	No evidence of emissions in excess of this limit was observed or has been indicated by any test results during normal operation.

Req. #	Generally Applicable Requirements	Emission Point	Inspector's Observations
Req-10	The Permittee must not burn fuel oil with a sulfur content greater than 15 ppm by weight (ppmw). SWCAA 400-050(2)	EU-2, EU-3, EU-9, EU-10, EU-11, EU-12	All reports indicate that only ultra-low sulfur fuel diesel (ULSD) has been burned in the past year. Because of the high production volume of ULSD, this is typically the cheapest form of diesel fuel.
Req-11	Permittee must not cause or allow emissions of particulate matter from a general process unit (excludes combustion) in excess of 0.1 gr/dscf of exhaust gas. Reference Method: 40 CFR 60 Appendix A Method 5 SWCAA 400-060	Plantwide	There are no identified general process units at this facility with a vent to ambient air.
Req-12	Permittee must conduct all abrasive blasting inside a structure designed to capture blast grit and overspray except for items too large to be reasonably handled indoors. SWCAA 400-070(8)	Plantwide	No abrasive blasting was observed. The blast structure at the coal plant has been abandoned.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-13	Permittee must install, calibrate, maintain, and operate continuous monitoring equipment for opacity for the bypass stack of Unit 2 in accordance with the requirements found in 40 CFR 51, App. P Section 3, 4, and 5 and 40 CFR 60 App. B – F as appropriate. SWCAA 400-105(4)(a)(i) and (4)(e)	EU-2	Opacity is measured in the ductwork upstream of the diversion to the FGD stack. Units were providing values during the inspection.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-14	Permittee must not cause or allow emissions of filterable particulate matter from the stack of Unit 2 in excess of 0.010 gr/dscf of exhaust gas corrected to 7% O_2. Reference Method: 40 CFR 60 Appendix A Method 5 ADP 97-2057R1 Section 34	EU-2	Test results indicate that scrubbed and unscrubbed PM emissions are well below this limit. A CAM plan is in place to assure compliance with this limit during normal operation. Maximum PM measured in the past year was 0.005 gr/dscf @ 7% O_2.
Req-15	Permittee must not cause or permit any emission which exceeds 20% opacity based on a 6-minute average, except for one 6-minute period/hour not to exceed 27% opacity. Permittee must not allow visible emissions to exceed 20% opacity for more than three minutes, in any one hour. Reference Method: EPA Method 9 and SWCAA Method 9 ADP 97-2057R1 Section 36	EU-2	No visible emissions were noticeable during my inspection. No excess emissions have been reported in the past year except that this limit could be exceeded during startups and shutdowns, especially when the ESPs are not operating.
Req-16	The Permittee must not cause or allow emissions of filterable particulate matter from the stack of Unit 2 in excess of either 0.030 lb/MMBtu or 0.30 lb/MWh gross output, 30-boiler operating day rolling average. These limits do not apply to periods of startup or shutdown as defined in 40 CFR 63.10042. Reference Method: 40 CFR 60 Appendix A Method 5 with increased filter temperature (320 ± 25°F filter temperature) and minimum 1 dry standard cubic meter sample volume per run or PM CEMS 40 CFR 63.9991(a)(1) – Reference to Table 2 40 CFR 63.10000(a) – Startup and shutdown exception 40 CFR 63.10005(a) – Explanation that either limit applies 40 CFR 63 Subpart UUUUU Table 2 Section 1(a) - Limits 40 CFR 63 Subpart UUUU Table 5 – Reference Methods	EU-2	All test results in the past year indicate compliance with these limits. Maximum PM measured in the past year was 0.009 lb/MMBtu.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-17	Permittee must not cause or allow total SO_2 emissions from the stack of Unit 2, the auxiliary boiler, and other emission points throughout the facility, combined, in excess of 10,000 tons per year in any rolling 12-month period. Reference Method: 40 CFR 75, Appendix A; 40 CFR 60 Appendix B Performance Specification 2 and 3: 40 CFR 60 Appendix F ADP 97-2057R1 Section 18	EU-2, EU-3	Starting on April 1, 2002, TransAlta has easily met this limit on a 12-month rolling total basis. 939 tons were emitted during calendar year 2024.
Req-18	Permittee must not cause or allow any unit to emit SO_2 in excess of 250 ppm on a dry basis, corrected to 7% O_2, 1-hour average except during startups, shutdowns and forced or planned outages of the SO_2 control system. Reference Method: 40 CFR 60 Appendix A Methods 3A, 6C ADP 97-2057R1 Sections 21(a) and 28(a)	EU-2	No exceedances of this limit were indicated in the CEMS reports for the past year.
Req-19	During startups, shutdowns, and forced or planned outages of the SO_2 control system, Permittee must not allow 1-hour average SO_2 emissions from the affected unit(s) in excess of 1,000 ppm. Reference Method: 40 CFR 60 Appendix A Method 6C ADP 97-2057R1 Section 21(b) and 21(c)	EU-2	There has been no exceedance of this limit in the past year. An exceedance is not possible unless the sulfur content of the coal being burned increases.
Req-20	The Permittee must schedule SO_2 emission control system outages to the maximum extent possible during daily or weekly load reduction periods. No planned SO_2 system outage is allowed from June 15 through September 15 of any year except when the unit burns no fuel. ADP 97-2057R1 Section 23	EU-2	No planned shutdowns of the scrubber system have occurred in the past year.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-21	The Permittee must not cause or allow emissions of sulfur dioxide from the stack of Unit 2 in excess of either 0.20 lbMMBtu or 1.5 lb/MWh gross output, 30-boiler operating day rolling average. These limits do not apply to periods of startup or shutdown as defined in 40 CFR 63.10042. Reference Method: SO_2 CEMS 40 CFR 63.9991(a)(1) – Reference to Table 2 40 CFR 63.10000(a) – Startup and shutdown exception 40 CFR 63.10005(a) – Explanation that either limit applies 40 CFR 63 Subpart UUUUU Table 2 Section 1(b) - Limits 40 CFR 63 Subpart UUUUU Table 5 – Reference methods, averaging period	EU-2	These limits are equivalent to approximately 100 ppm SO_2 and have been met by a wide margin in the past year.
Req-22	Permittee must: (1) hold SO_2 Acid Rain allowances, as of the allowance transfer deadline, in the source's account (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of SO_2 for the previous calendar year from the affected units at the source; and (2) comply with the applicable Acid Rain emissions limitation for SO_2. (See Appendix B Acid Rain Permit). Reference Method: 40 CFR 75 40 CFR 72.9(c)(1) WAC 173-406-106(3)(a)(i)	EU-2	TransAlta is allocated 39,481 allowances each year and uses only a fraction of that amount. TransAlta's account held 496,713 remaining allowances at the trading deadline for 2024. This is no longer a meaningful limit because SO_2 allowances no longer have significant value.
Req-23	The Permittee must forfeit ownership of SO_2 Acid Rain allowances to SWCAA equal to 1.5 times the quantity of emissions in excess of the 10,000 ton annual limit calculated on a calendar year basis. Reference Method: 40 CFR 75 ADP 97-2057R1 Section 28(f)	EU-2	Plantwide SO_2 emissions were 939 tons for 2024.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-24	The original stack may remain for bypass provided certified CEMS are maintained to monitor SO_2 emissions from the bypass stack. If SO_2 emissions from the original stack are not monitored by certified functioning CEMS, the Permittee must only use the original stack during extreme emergency conditions. ADP 97-2057R1 Section 29	EU-2	TransAlta is currently maintaining certified CEMS in the ductwork upstream of the bypass stack. A single analyzer is used for each unit, swapping between the two inlet ducts every 7.5 minutes. The most recent RATA of these systems was in August 2025.
Req-25	SO_2 emissions from Unit 2 must not exceed 1,350 pounds per hour (1-hour average). Compliance with the SO_2 emission limit must be based on using SO_2 emissions data from a Continuous Emissions Monitoring System (CEMS) operated in accordance with 40 CFR 75. Only unadjusted, quality-assured SO_2 concentration values and flow rate data must be used in the emissions calculations. Bias adjustment factors and 40 CFR 75 substitute data values must not be used. The CEMS must provide valid hourly SO_2 emissions for at least 95% of the hours that the boiler is operated during each calendar month except for periods of monitoring system downtime, provided that the owner or operator demonstrated that the downtime was not a result of inadequate design, operation, or maintenance, or any other reasonable preventable conditions, and any necessary repairs to the monitoring system are conducted in a timely manner. ADP 16-3202 Paragraphs 13 and 14	EU-2	No exceedances are indicated in the CEMS data.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-26	The Permittee must not cause or allow emissions of mercury from the stack of Unit 2 in excess of either 1.2 lb/TBtu or 0.013 lb/GWh gross output, 30-boiler operating day rolling average. These limits do not apply to periods of startup or shutdown as defined in 40 CFR 63.10042. Reference Method: Hg CEMS or sorbent trap monitoring system 40 CFR 63.9991(a)(1) – Reference to Table 2 40 CFR 63.10000(a) – Startup and shutdown exception 40 CFR 63.10005(a) – Explanation that either limit applies 40 CFR 63 Subpart UUUUU Table 2 Section 1(c) - Limits 40 CFR 63 Subpart UUUUU Table 5 – Reference methods, averaging period	EU-2	CEMS data indicates no exceedance of these limits in the past year.
Req-27	Emissions of nitrogen oxides must not exceed 0.30 lb/MMBtu for those hours when the unit's generating load is 360 MW gross or greater. This annual average is calculated as the combined arithmetic sum of hourly emission rates when generating load is 360 MW gross, or greater, during the calendar year. Reference Method: 40 CFR 75 ADP 97-2057R1 Section 30	EU-2	CEMS data indicates no exceedance of this limit in the past year.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-27b	Emissions of nitrogen oxides from Unit 2 are limited to 0.18 lb/MMBtu (30-boiler operating day rolling average). The Permittee may use a variety of means as necessary to control emissions of nitrogen oxides to meet the prescribed NO_X limit including the Combustion Optimization System with Neural Network, the SNCR, Low NOx Burners, boiler control, variety (source) of coal, or any combination thereof. Compliance with the nitrogen oxides emission limitation will be determined by use of a continuous emission monitoring system meeting the requirements of 40 CFR Part 75. For any hour in which coal is combusted in a unit, the owner/operator of each unit must calculate the hourly nitrogen oxides concentration in lb/MMBtu at the CEMS installed in accordance with the requirements of 40 CFR Part 75. The 30-day average lb/MMBtu rate is calculated by summing the hourly emissions in pounds (unit lb/MMBtu times unit heat input) and dividing that by the sum of the hourly heat inputs in million Btu. At the end of that boiler's operating day, the owner/operator must calculate and record a new 30-day rolling average emission rate in lb/MMBtu from all valid hourly data for that boiler's operating day and for that boiler's previous 29 successive boiler operating days. An hourly average nitrogen oxides emission rate is valid only if the minimum number of data points, as specified in 40 CFR 75, is acquired as necessary to calculate nitrogen oxides emissions and heat rate. Data reported to meet these requirements must not include data substituted using the missing data substitution procedures of subpart D of 40 CFR part 75, and the data must not have been bias adjusted according to the procedures of 40 CFR part 75. A boiler operating day is a 24-hour period between 12 midnight and the following midnight during which coal is combusted at any time in the boiler. It is not necessary for coal to be combusted for the entire 24-hour period. Second Revision of BART Order No. 6426 Conditions 1.1, 1.2, 3.3, and 5	EU-2	CEMS data indicates no exceedance of this limit in the past year.
Req-28	Reserved		
Req-29	Reserved		

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-30	Emissions of ammonia from the coal-fired utility steam generating unit is limited to a maximum of 10 ppmvd, 30 operating day rolling average. The ammonia concentration measured during the periodic emissions testing required by M8 is the 30 operating day rolling average value used for compliance starting on the date of the completion of the test until the completion of the next required periodic emission test. Second Revision of BART Order No. 6426 Conditions 2.1 and 4.1.4	EU-2	No urea has been injected in the past year; therefore, ammonia emissions have not been generated. The urea tanks are reportedly empty.
Req-31	Unit 1 and Unit 2 must permanently cease coal-fired power generation operations as follows: (a) One of the units must cease no later than December 31, 2020. (b) The other unit must cease no later than December 31, 2025. These conditions do not apply in the event the Washington Department of Ecology determines as a requirement of state or federal law or regulation that the selective catalytic reduction technology must be installed on either coal fired unit. Second Revision of BART Order No. 6426 Condition 3	EU-1, EU-2	Unit 1 permanently ceased operation December 31, 2020. Vital parts of Unit 1 have been removed from the site, rendering it inoperable.
Req-32	Reserved		
Req-33	Reserved		
Req-34	Reserved		
Req-35	NO_X emissions must not exceed 0.40 lb/million Btu annual average for Unit 2 (see Appendix B Acid Rain Permit). Reference Method: 40 CFR 75 40 CFR 76.7(a)(1) WAC 173-406-106(4)	EU-2	CEMS data indicates no exceedance of this limit in the past year.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-36	Permittee must not cause or allow carbon monoxide emissions in excess of 200 ppm, on a dry basis, corrected to 7% O_2, annual (calendar year) average. Reference Method: Averaging of plant CO CEMS data as provided in M8 ADP 97-2057R1 Section 39	EU-2	CEMS indicated compliance for 2024. CO concentrations were averaging above this value for the first half of 2025.
Req-37	Permittee must certify, operate, and maintain continuous emissions monitoring systems (CEMS) and a continuous opacity monitoring system (COMS) with an automated data acquisition and handling system for determining and recording all SO_2, NO_X, and CO_2 emissions from the scrubber stack and all SO_2, NO_X, and CO_2 emissions and opacity from the bypass stack as required by 40 CFR 75. 40 CFR 75.10(a)	EU-2	CEMS data from the scrubber stack has been reported quarterly. All systems were reporting during the inspection. Data substitution rather than monitoring is conducted for bypass NO_X during startup / shutdown as allowed by 40 CFR 75.
Req-38	The Permittee must conduct a tune-up of Unit 2 initially and every 48 months thereafter in accordance with the requirements of 40 CFR 63.10021(e) and Table 3 of 40 CFR 63 Subpart UUUUU. 40 CFR 63.10000(e) – Requirement for periodic tune-ups 40 CFR 63.10006(i)(2) – Frequency of periodic tune-ups 40 CFR 63.10021(e) – Procedures and frequency 40 CFR 63 Subpart UUUUU Table 3 Section 1 40 CFR 63 Subpart UUUUU Table 7 Section 5	EU-2	The most recent tune-up was completed in a timely manner and a final report received by SWCAA on October 7, 2022.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-39	For startup of Unit 2, the Permittee must comply with one of the options provided in Table 3 of 40 CFR 63 Subpart UUUUU. If Option 2 is chosen, the Permittee must use clean fuels to the maximum extent possible during the startup period and engage both sets of electrostatic precipitators within 1 hour of firing coal. All other control devices must be engaged as expeditiously as possible, considering safety and manufacturer/supplier recommendations. Applicable emission limits from 40 CFR 63 Subpart UUUUU apply within 4 hours of the start of electricity generation. Startup ends when all applicable emission control devices are engaged (ESPs, mercury control system and flue gas desulfurization system) or 4 hours after the electrical generating unit generates electricity or useful thermal energy, whichever is earlier. While firing coal or residual oil during shutdown, the Permittee must operate all applicable control technologies, and continue to operate those control devices after the cessation of coal or residual oil being fed into the boiler and for as long as possible thereafter considering operational and safety concerns. Shutdown ends when the electrical generating unit no longer generates electricity or makes useful thermal energy and no fuel is being fired in the electrical generating unit. The Permittee must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in 40 CFR 63 Subpart UUUUU. 40 CFR 63.10000(a) for startup and shutdown work practice requirements 40 CFR 63.10042 "startup" and "shutdown" definitions 40 CFR 63 Subpart UUUUU Table 3 Sections 3 and 4	EU-2	TransAlta chose option 2 through 2024. This option was only available until January 1, 2025, after which the second definition of startup in 63.10042 no longer applies. Until 2025, the ESPs and wet scrubber must be engaged by the time coal firing begins and the emission limits apply (startup ends) as soon as steam is used. A review of specific startup and shutdown reports indicates compliance in 2024 but not in 2025. In 2025, the scrubber was not fully engaged until after coal was fired.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-40	At all times, including periods of startup, shutdown, and malfunction, the Permittee must, to the extent practicable, maintain and operate air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to SWCAA, which may include, but is not limited to, monitoring results, review of operating and maintenance procedures and records, and inspection of the source. [40 CFR 63.10000(b), ADP 97-2057R1 Section 48] The flue gas desulfurization system must be operated at all times consistent with 40 CFR 63.10000(b) except as allowed during startup by Table 3 of Subpart UUUUU of Part 63. [40 CFR 63.9991(c)(2), 40 CFR 63 Subpart UUUUU Table 3, Section 3] 40 CFR 63.9991(c)(2) 40 CFR 63.10000(b) ADP 97-2057R1 Section 48	EU-2	SO_2 concentrations have been relatively low, and TransAlta was operating two scrubbing levels during the inspection as appropriate. A past test has indicated that operating only one spray level would be unacceptable. A number of ESP fields are typically out of service awaiting servicing during longer shutdown periods, but this is acceptable so long as the scrubber inlet opacity levels are maintained.
Req-41	Permittee must not cause or allow total annual fuel oil combusted in the auxiliary boiler in excess of 600,000 gallons per year. ADP 97-2057R1 Section 45	EU-3	159,215 gallons reported for 2024.
Req-42	Effective January 31, 2016, the Permittee must operate and maintain the Auxiliary Boiler in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to SWCAA, which may include, but is not limited to, monitoring results, review of operating and maintenance procedures and records, and inspection of the source. 40 CFR 63.7500(a)(3)	EU-3	This boiler was not in use during the inspection.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-43	A tune-up of the Auxiliary Boiler must be conducted initially and every 5 years thereafter, no later than 61 months after the previous tune-up. The initial tune-up must be conducted no later than January 31, 2016. Each tune-up must be conducted in accordance with 40 CFR 63.7540(a)(10)(i) through (vi). The burner inspection specified in 40 CFR 63.7540(a)(10)(i) may be delayed until the next scheduled or unscheduled unit shutdown; however the burner must be inspected at least once every 72 months. 40 CFR 63.7500(c) 40 CFR 7505(a) 40 CFR 63.7510(e) 40 CFR 63.7515(d) 40 CFR 63.7540(a)(12) 40 CFR 63 Subpart DDDDD Table 3	EU-3	The initial tune-up was conducted January 29, 2016. The subsequent tune-up was due February 2021 and was reportedly completed in January 2021, but a report was never submitted to TransAlta by the contractor. The tune-up was completed in May 2022 after SWCAA issued NOV 10123 and TransAlta subsequently completed repairs of the unit.
Req-44	The opacity of emissions from the loading of fly ash trucks from the 6050 unloaders must not exceed twenty percent for more than 3 minutes in any one-hour period as determined in accordance with SWCAA 400, Appendix A, Method 9. ADP 01-2403 Section 11(a)	EU-4	Not operating during the inspection. No excess emissions have been reported. When I visited the limited purpose landfill for such ash in 2022 it hadn't been used in quite some time (years probably based on vegetation growth). During my inspection of the mine in 2023 Mr. Marc Read indicated they had not placed any new material in the landfill. During the 2025 inspection Mr. Bocook indicated these units have not been used in recent years.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-45	The opacity of emissions from the Unit 2 turbine lube oil mist eliminator stack must not exceed five percent for more than 3 minutes in any one-hour period as determined in accordance with SWCAA 400, Appendix A, Method 9. ADP 01-2403 Section 11(b)	EU-6	No visible emissions were evident.
Req-46	Emissions of PM_{10} from the Coal Unloading Facility must not exceed 2,411 pounds per year. Annual emissions must be calculated using the methodology identified in Section V of the Title V Basis Statement. ADP 11-2972 Condition 2	EU-4	< 28 pounds in 2024.
Req-47	The opacity of emissions from all emission points within the Coal Unloading Facility must not exceed zero percent for more than three minutes in any one hour period as determined in accordance with SWCAA 400, Appendix A, Method 9. ADP 11-2972 Condition 3	EU-4	No coal was being unloaded during the inspection. Spray nozzles were in place.
Req-48	Coal drop (transfer) points associated with the Coal Unloading Facility must utilize a high pressure water spray system to control fugitive dust during coal unloading and transfer operations. Water pressure at the spray/fog nozzles must be maintained at 80 psig or greater during coal unloading and coal transfer operations. A functional pressure gauge must be maintained onsite and a connection point provided for the gage for the purpose of demonstrating compliance with this pressure limit. ADP 11-2972 Condition 8	EU-4	No coal was being unloaded during the inspection.
Req-49	Emissions of PM_{10} from the FGD Bleed Treatment Lime Storage Silo must not exceed 0.005 grains per dry standard cubic foot (1-hour average). Reference Method: 40 CFR 60 Appendix A Method 5 or 201A ADP 05-2636 Condition 1	EU-4	Lime was not being loaded during the inspection. I did not notice any evidence of excess emissions from the ground level.
Req-50	The opacity of emissions from the FGD Bleed Treatment Lime Storage Silo must not exceed zero percent for more than three minutes in any one hour period as determined in accordance with SWCAA 400, Appendix A, Method 9. ADP 05-2636 Condition 2	EU-4	Lime was not being loaded during the inspection.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-51	The opacity of emissions from the Journal Shop Baghouse must not exceed zero percent for more than three minutes in any one hour period as determined in accordance with SWCAA 400, Appendix A, Method 9. ADP 08-2779 Condition 1	EU-8	This unit was not in use during the inspection.
Req-52	The Journal Shop Baghouse must be operated to collect welding fume whenever welding activities are taking place in the Journal Shop. The Journal Shop baghouse must be maintained in good repair and must utilize afterfilters meeting a HEPA or better particulate matter collection efficiency (99.97% or better on particles measuring 0.3 microns or greater in diameter). ADP 08-2779 Condition 2	EU-8	The unit was not in use during the inspection. The collection hood was in place. The catch barrel was mostly empty and the HEPA afterfilter was in place.
Req-53	The Permittee must conduct the following maintenance for Emergency Diesel Generator 1. (a) Change oil and filter every 500 hours of operation or annually, whichever comes first except as provided in 40 CFR 63.6625(i); (b) Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and (c) Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. 40 CFR 63.6640(a) 40 CFR 63.6602 and Table 2c SWCAA 400-075	EU-9	I have requested copies of maintenance records.
Req-54	The Permittee must minimize the time Emergency Diesel Generator 1 spends at idle and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes. 40 CFR 63.6602 40 CFR 63.6625(h) and Table 2c SWCAA 400-075	EU-9	The unit operated only 22 hours in 2024.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-55	The Permittee must operate and maintain Emergency Diesel Generator 1 according with the Small Engine Maintenance Plan detailed in Appendix C. 40 CFR 63.6625(e) 40 CFR 63.6640(a) and Table 6 SWCAA 400-075	EU-9	I have requested copies of maintenance records.
Req-56	The Permittee must maintain a non-resettable hour meter on Emergency Diesel Generator 1 and Emergency Diesel Generator 2. 40 CFR 60.4209(a) – Emergency Diesel Generator 2 40 CFR 63.6625(f) – Emergency Diesel Generator 1 SWCAA 400-075	EU-9, EU-10	An hourmeter was installed.
Req-57	At all times Emergency Diesel Generator 1 must be operated and maintained in a manner consistent with safety and good air pollution control practices for minimizing emissions. 40 CFR 63.6605(b), SWCAA 400-075	EU-9	No evidence of improper operations.
Req-58	Operation of Emergency Diesel Generator 1 and Emergency Diesel Generator 2 for maintenance checks and readiness testing must not exceed 100 hours per year each. Emergency operation of the emergency generator engines is not limited. A nonresettable time totalizer must be installed on each engine and used to measure hours of operation. Emergency Diesel Generator 1 and Emergency Diesel Generator 2 may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. 40 CFR 63.6640(f) - Em. Diesel Generator 1 40 CFR 60.4211(f)(2) – Em. Diesel Generator 2 SWCAA 400-075 ADP 16-3188 Condition 5	EU-9, EU-10	These units operated for 22 and 26 hours respectively in 2024.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-59	Operation of Emergency Diesel Generator 1 and Emergency Diesel Generator 2 must be limited to maintenance checks, readiness testing, and as necessary for emergency service. 40 CFR 63.6640(f)(2) -Em. Diesel Generator 1 40 CFR 60.4211(f)(2) – Em. Diesel Generator 2 SWCAA 400-075 ADP 16-3188 Condition 6	EU-9, EU-10	The very limited operation recently would indicate they have only been operated for readiness testing.
Req-60	Emissions from the Coal Unloading Facility Emergency Diesel Sump Pump Engine must not exceed: Pollutant — Emission Limit Nitrogen Oxides — 0.25 tons per year Carbon Monoxide — 0.044 tons per year PM — 0.0055 tons per year PM_{10} — 0.0055 tons per year $PM_{2.5}$ — 0.0055 tons per year Reference Methods: EPA Methods 1-5, 7E, 10, 201A Annual emissions must be calculated using the methodology identified in Section V of the Title V Basis Statement. ADP 11-2972 Condition 5	EU-12	Each of these limits was met by a wide margin.
Req-61	Visible emissions from the Coal Unloading Facility Emergency Diesel Sump Pump Engine must not exceed five percent opacity for more than 3 minutes in any one hour period as determined in accordance with SWCAA Method 9 (See Appendix A of SWCAA 400) except during startup. For the purposes of this requirement, the startup period ends when the earlier of the following operating events occurs: (a) The engine has reached normal operating temperature; or (b) The engine has been operating for 15 minutes. Reference Method: SWCAA Method 9 ADP 11-2972 Condition 6	EU-12	This unit operates infrequently (5.7 hours in 2024). I have never observed it in operation.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-62	The Coal Unloading Facility Emergency Diesel Sump Pump Engine must only be fired on No. 2 diesel or better. The sulfur content of the fuel fired in the diesel engine must not exceed 0.0015% by weight (15 ppm). A fuel certification from the fuel supplier may be used to demonstrate compliance with this requirement. 40 CFR 60.4207(b) SWCAA 400-050(2) ADP 11-2972 Condition 9	EU-12	Only ultra-low sulfur fuel is used at the facility or readily available.
Req-63	Operation of the Coal Unloading Facility Emergency Diesel Sump Pump Engine must be limited to maintenance checks, readiness testing, and as necessary to provide emergency or backup pumping. The engine may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Operation for maintenance checks and readiness testing must not exceed 100 hours per year. 40 CFR 60.4211(f)(2) ADP 11-2972 Condition 10	EU-12	No evidence of any other operation recently. Only 5.7 hours of operation in 2024.
Req-64	The Coal Unloading Facility Emergency Diesel Sump Pump Engine must be operated no more than 200 hours per year. A nonresettable time totalizer must be installed and used to measure hours of operation. ADP 11-2972 Condition 11	EU-12	5.7 hours of operation in 2024.
Req-65	The exhaust from the Coal Unloading Facility Emergency Diesel Sump Pump Engine must be discharged vertically. Any device that obstructs or prevents vertical discharge is prohibited. ADP 11-2972 Condition 12	EU-12	The exhaust is angled away from the coal receiving hopper to prevent coal from falling down the exhaust. This appears to be a necessary adaptation and the high temperature exhaust retains a strong vertical component.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-66	Except as provided in 40 CFR 60.4211(g), the Coal Unloading Facility Emergency Diesel Sump Pump Engine must be operated and maintained according to the manufacturer's emissions-related written instructions and the Permittee may only change those emissions-related settings that are permitted by the manufacturer. The manufacturer's written instructions have been summarized in Appendix C of this Permit. 40 CFR 60.4211(g) contains alternative requirements, including a source test requirement, if the Permittee chooses to deviate from the manufacturer's written instructions. 40 CFR 60.4211(a) SWCAA 400-115 ADP 11-2972 Condition 13	EU-12	I have requested copies of maintenance records.
Req-67	Emissions from the Fire Pump Engine must not exceed: Pollutant — Emission Limit Nitrogen Oxides — 0.28 tons per year Carbon Monoxide — 0.14 tons per year PM — 0.013 tons per year PM_{10} — 0.013 tons per year $PM_{2.5}$ — 0.013 tons per year Annual emissions must be calculated using the methodology identified in Section V of the Title V Basis Statement. Reference Methods: EPA Methods 1-5, 7E, 10, 201A ADP 16-3188 Condition 1	EU-11	Emissions were far below these levels for 2024 based on 17 hours of operation.
Req-68	Visible emissions from the Fire Pump Engine and Emergency Diesel Generator 2 must not exceed five percent opacity for more than 3 minutes in any one hour period as determined in accordance with SWCAA Method 9 (See Appendix A of SWCAA 400) except during startup. For the purposes of this requirement, the startup period ends when the earlier of the following operating events occurs: (a) The engine has reached normal operating temperature; or (b) The engine has been operating for 15 minutes. ADP 16-3188 Condition 2	EU-10, EU-11	I have not observed these units during operation. The exhausts are not excessively sooty.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-69	Except as provided in 40 CFR 60.4211(g), the Fire Pump Engine and Emergency Diesel Generator 2 must be operated and maintained according to the manufacturer's emissions-related written instructions and the Permittee may only change those emissions-related settings that are permitted by the manufacturer. The manufacturer's written instructions have been summarized in Appendix C of this Permit for the Fire Pump Engine. 40 CFR 60.4211(g) contains alternative requirements, including a source test requirement, if the Permittee chooses to deviate from the manufacturer's written instructions. 40 CFR 60.4211(a) SWCAA 400-115	EU-10, EU-11	I have requested copies of maintenance records.
Req-70	The Fire Pump Engine and Emergency Diesel Generator 2 must only be fired on No. 2 diesel or better. The sulfur content of the fuel fired in the diesel engines must not exceed 0.0015% by weight (15 ppm). A fuel certification or receipt from the fuel supplier, or test results using an appropriate method listed in 40 CFR 60.17, may be used to demonstrate compliance with this requirement. 40 CFR 60.4207(b) SWCAA 400-050(2) ADP 16-3188 Condition 3	EU-10, EU-11	Only ultra-low sulfur diesel is purchased at the facility.
Req-71	The Fire Pump Engine must be operated no more than 504 hours per year. A nonresettable time totalizer must be installed on the engine and used to measure hours of operation. ADP 16-3188 Condition 4	EU-11	17 hours of operation reported in 2024.
Req-72	The exhaust from the Fire Pump Engine and Emergency Diesel Generator 2 must be discharged vertically. Any device that obstructs or prevents vertical discharge is prohibited. ADP 16-3188 Condition 7	EU-10, EU-11	These exhausts are vertical.

<table>
<tr><th>Req. #</th><th>Coal Plant Requirements</th><th>Emission Point</th><th>Inspector's Observations</th></tr>
<tr><td>Req-73</td><td>Emissions of filterable particulate matter (PM, PM_{10}, and $PM_{2.5}$) from each of the mercury control project material handling exhaust stacks must not exceed 0.005 gr/dscf (1-hour average) and the quantities identified below:

<table>
<tr><th>Generating Equipment</th><th>Short-Term Limit (1-hour average)</th><th>Annual Limit</th></tr>
<tr><td>SEA System 1</td><td>0.048 lb/hr</td><td>0.21 tons per year</td></tr>
<tr><td>SEA System 2</td><td>0.048 lb/hr</td><td>0.21 tons per year</td></tr>
<tr><td>Sorbent Silo 1</td><td>0.015 lb/hr</td><td>0.07 tons per year</td></tr>
<tr><td>Sorbent Silo 2</td><td>0.015 lb/hr</td><td>0.07 tons per year</td></tr>
<tr><td>Fly Ash Bin 11</td><td>0.63 lb/hr</td><td>2.77 tons per year</td></tr>
<tr><td>Fly Ash Bin 12</td><td>0.63 lb/hr</td><td>2.77 tons per year</td></tr>
<tr><td>Fly Ash Bin 14</td><td>0.63 lb/hr</td><td>2.77 tons per year</td></tr>
<tr><td>Fly Ash Bin 14 Air Slide to Bin 11 Air Slide</td><td>0.039 lb/hr</td><td>0.17 tons per year</td></tr>
<tr><td>Fly Ash Bin 14 to 6050 Air Slide</td><td>0.026 lb/hr</td><td>0.11 tons per year</td></tr>
</table>
Annual emissions must be calculated using the methodology identified in Section V of the Title V Basis Statement.

Reference Method: EPA Method 5 or 17

ADP 11-2984 Condition 1</td><td>EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21</td><td>Only fly ash bins 11 and 12 remain in service. The most recent testing of these bins in September 2021 indicated emission concentrations of 0.001 gr/dscf for each unit. The filter pressure drop was at the target level of 3" w.c.</td></tr>
<tr><td>Req-74</td><td>Visible emissions from each emission unit installed as part of the mercury control project must not exceed zero percent opacity for more than 3 minutes in any one hour period as determined in accordance with SWCAA Method 9 (See Appendix A of SWCAA 400). This limit applies to stack exhausts as well as fugitive leaks from equipment.

ADP 11-2984 Condition 2</td><td>EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21</td><td>No visible emissions were apparent during the inspection.</td></tr>
</table>

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-75	Each pollution control device must be operated whenever the processing equipment served by that control device is in operation. Each control device must be maintained in good working order. Furthermore, control devices must be operated in a manner that minimizes emissions. ADP 11-2984 Condition 3	EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21	The operating units (Bins 11 and 12) appeared to be operating properly at the target differential pressure of 3" w.c. each.
Req-76	Exhaust from each of the mercury control project material handling filters must be discharged vertically. Any device that obstructs or prevents vertical discharge is prohibited. ADP 11-2984 Condition 4	EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21	All exhausts that I could see were vertical (Bin 14 air slide exhaust is difficult to access and was not observed directly but is also out of service). Bin 14 was not in use and would only be used for off-specification fly ash which is highly unlikely since mercury is being controlled without the injection of powdered activated carbon (the main reason off-specification fly ash might be created).
Req-77	Each fly ash bin baghouse and dust collector must be equipped with a differential pressure gauge capable of continuously measuring the pressure drop across filtration media in the unit. ADP 11-2984 Condition 5	EU-17, EU-18, EU-19	Gauges were installed and functioning on the operating units (11 and 12).

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-78	Emissions of filterable particulate matter (PM, PM_{10}, and $PM_{2.5}$) from the Fly Ash Weigh Bin Baghouse must not exceed 0.002 gr/dscf (1-hour average) and the quantities identified below: Generating Equipment — Short-Term Limit (1-hour average) — Annual Limit Fly Ash Weigh Bin — 0.046 lb/hr — 0.20 tons per year Reference Method: EPA Method 5 or 17 ADP 12-3016 Condition 1	EU-4	Test results from 10/19/2012 testing indicate PM concentration of 0.0005 gr/dscf. Visible emissions were apparent 10/23/2025. NOV 10642 was issued for this violation.
Req-79	Visible emissions from the Fly Ash Weigh Bin must not exceed zero percent opacity for more than 3 minutes in any one hour period as determined in accordance with SWCAA Method 9 (See Appendix A of SWCAA 400). This limit applies to stack exhausts as well as fugitive leaks from equipment. Reference Method: SWCAA Method 9 ADP 12-3016 Condition 2	EU-4	Visible emissions were apparent 10/23/2025. NOV 10642 was issued for this violation.
Req-80	The Weigh Bin Baghouse must be used to control emissions whenever the equipment served by that baghouse is in operation. ADP 12-3016 Condition 3	EU-4	The fly ash weigh bin baghouse was running during the inspection even when no truck was being loaded.
Req-81	Exhaust from the Fly Ash Weigh Bin Baghouse must be discharged vertically. Any device that obstructs or prevents vertical discharge is prohibited. ADP 12-3016 Condition 4	EU-4	The stack remains vertical.
Req-82	The Fly Ash Weigh Bin Baghouse must be equipped with a differential pressure gauge capable of continuously measuring the pressure drop across filtration media in the unit. ADP 12-3016 Condition 5	EU-4	Due to the presence of visible emissions when fly ash was not being loaded into trucks, the operators turned off the unit before we climbed down to the platform with the filter.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-83	Emissions from fine coal recovery must not exceed: Pollutant — Emission Limit PM — 0.009 tons per year PM_{10} — 0.003 tons per year $PM_{2.5}$ — 0.0005 tons per year Annual emissions must be calculated using the methodology identified in Section V of the Title V Basis Statement. ADP 14-3093 Condition 1	EU-22	The fine coal recovery process was retired effective June 30, 2021. The equipment has been removed.
Req-84	Visible emissions from fine coal handling and conveying equipment must not exceed 0% opacity for more than 3 minutes in any one hour period as determined in accordance with SWCAA Method 9 (See Appendix A of SWCAA 400). Reference Method: SWCAA Method 9 ADP 14-3093 Condition 2	EU-22	The fine coal recovery process was retired effective June 30, 2021. The equipment has been removed.
Req-85	Visible emissions from fine coal handling and conveying equipment must be less than 10% opacity (1-hour average) as determined in accordance with EPA Method 9. Reference Method: EPA Method 9 40 CFR 60.254(b)(1) ADP 14-3093 Condition 3	EU-22	The fine coal recovery process was retired effective June 30, 2021. The equipment has been removed.
Req-86	The transfer of fine coal from the stacker to the fine coal stockpile (TP-05) must be controlled as necessary using a high pressure water spray system or other wet suppression system reviewed and approved by SWCAA to provide equivalent or superior control of particulate matter emissions. Each high pressure spray system must maintain 80 psig or greater during operation. A functional pressure gauge must be maintained onsite and a connection point provided for the gage for the purpose of demonstrating compliance with this pressure limit. ADP 14-3093 Condition 4	EU-22	The fine coal recovery process was retired effective June 30, 2021. The equipment has been removed.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
Req-87	The fine coal stockpile must be watered as necessary to control fugitive dust emissions. ADP 14-3093 Condition 5	EU-22	The fine coal recovery process was retired effective June 30, 2021. The equipment has been removed.
Req-88	Additional wet suppression must be provided as necessary to control fugitive dust from material handling equipment in the event that process controls or enclosures are insufficient to meet the visible emission limits. ADP 14-3093 Condition 7	EU-22	The fine coal recovery process was retired effective June 30, 2021. The equipment has been removed.
Req-89	The Permittee must develop and operate in accordance with a fugitive coal dust emissions control plan for any clean coal stockpile subject to 40 CFR 60 Subpart Y. 40 CFR 60.254(c) ADP 14-3093 Condition 8	EU-22	The fine coal recovery process was retired effective June 30, 2021. The equipment has been removed.

Nonroad Engine Permit 09-2876 – Jetstream Power Washer (nonroad engine)
Note that nonroad engines are not "stationary sources" and therefore these requirements cannot be included in Title V Air Operating Permit. The primary requirements are listed below:

Req. #	Jetstream Power Washer Requirements	Emission Point	Inspector's Observations
1.	Emissions from the Jetstream Pressure Washer Engine shall not exceed: Pollutant — Emission Limit (pounds per day) Nitrogen oxides — 40 Carbon monoxide — 35 PM_{10} — 2 $PM_{2.5}$ — 2 Annual emissions shall be calculated using the emission factors presented in the Technical Support Document for this Nonroad Engine Permit unless more recent source test data has been collected.	No EU# assigned	Compliance is presumed unless there is indication of improper operation.
2.	Visible emissions from the Jetstream Pressure Washer Engine shall not exceed ten percent opacity for more than 3 minutes in any one hour period as determined in accordance with SWCAA Method 9 (See Appendix A of SWCAA 400) except during startup. For the purposes of this requirement, the startup period ends when the earlier of the following operating events occurs: (a) The engine has reached normal operating temperature; or (b) The engine has been operating for 15 minutes.	No EU# assigned	I have not observed this unit in operation.
3.	Exhaust from the Jetstream Pressure Washer Engine shall be discharged vertically. Any device that obstructs or prevents vertical discharge is prohibited.	No EU# assigned	The last time I saw this unit (in storage), the exhaust was vertical.
4.	The Jetstream Pressure Washer Engine shall only be fired on #2 diesel or better. The sulfur content of the fuel fired in the diesel engine shall not exceed 0.0015% by weight (15 ppm). A fuel certification from the fuel supplier or test results using an appropriate method listed in 40 CFR 60.17 may be used to demonstrate compliance with this requirement.	No EU# assigned	TransAlta reports fuel sulfur content quarterly. All fuel has met this standard.

Req. #	Jetstream Power Washer Requirements	Emission Point	Inspector's Observations
5.	A nonresettable time totalizer shall be installed on the Jetstream Pressure Washer Engine and used to measure hours of operation.	No EU# assigned	We did not visit this unit during the inspection. 10.2 hours of operation were reported for 2024.
7.	The following information shall be collected, recorded at the intervals specified below, and readily available on-site for inspection: (a) The total number of hours the Jetstream Pressure Washer Engine is operated shall be recorded for each calendar year; (b) Fuel purchase receipts for the Jestream Pressure Washer Engine shall be retained for each purchase; (c) For each diesel fuel delivery, the sulfur content of the diesel fuel shall be recorded. A fuel certification from the fuel supplier or test results using an appropriate method listed in 40 CFR 60.17 may be used to comply with this requirement; (d) Upset conditions that cause excess emissions shall be recorded for each occurrence; and (e) All air quality related complaints, including odor complaints, received by the permittee and the results of any subsequent investigation or corrective action shall be recorded for each occurrence.	No EU# assigned	a. 10.2 hrs reported for 2024 b. Fuel is purchased in bulk. Fuel receipts are not for individual equipment. c. Only ultra-low sulfur fuel is available locally. d. None reported. e. No complaints reported.
13.	The following emissions related records shall be reported to SWCAA by March 15th for the previous calendar year: (a) The total number of hours the Jetstream Pressure Washer Engine was operated; and (d) Air emissions of criteria air pollutants, volatile organic compounds, toxic air pollutants (TAPs), and hazardous air pollutants (HAPs).	No EU# assigned	This information for 2024 was submitted with the annual emissions inventory.

ADP / Nonroad Engine Permit 16-3188 – Pump-05 and Pump-07 (nonroad engines)
Note that nonroad engines are not "stationary sources" and therefore these requirements cannot be included in Title V Air Operating Permit. The primary requirements are listed below:

Req. #	Pump-05 and Pump-07 Requirements	Emission Point	Inspector's Observations
2	Visible emissions from the Pump-05 Engine and the Pump-07 Engine must not exceed five percent opacity for more than 3 minutes in any one hour period as determined in accordance with SWCAA Method 9 (See Appendix A of SWCAA 400) except during startup. For the purposes of this requirement, the startup period ends when the earlier of the following operating events occurs: (a) The engine has reached normal operating temperature; or (b) The engine has been operating for 15 minutes.	No EU# assigned	We did not see either of these units during the inspection. I could not see any engines operating at the pond system (where they would be used).
3.	The Pump-05 Engine, the Pump-07 Engine must only be fired on #2 diesel or better. The sulfur content of the fuel fired in the diesel engines must not exceed 0.0015% by weight (15 ppm). A fuel certification or receipt from the fuel supplier, or test results using an appropriate method listed in 40 CFR 60.17, may be used to demonstrate compliance with this requirement.	No EU# assigned	Only ultra-low sulfur diesel is purchased for the facility.
8.	The following information must be collected, recorded at the intervals specified below, and readily available on-site for inspection: (a) The sulfur content of the diesel burned in the Pump-05 Engine and the Pump-07 Engine must be determined and recorded for each fuel delivery. A fuel supplier certification or receipt may be used in lieu of new fuel testing; (b) The permittee must document the total number of hours the Pump-05 Engine and the Pump-07 Engine operate each year; and (c) Upset conditions that cause excess emissions must be recorded for each occurrence.	No EU# assigned	a. Only ultra-low sulfur diesel is purchased for the facility. b. This information for 2024 was submitted with the annual emissions inventory. c. No upsets have been reported.
9.	With the exception of data recorded by an automated data acquisition system, all records must include the date and name of the person making each entry.	No EU# assigned	I did not review records for this equipment during this inspection.
10.	All records required by this Permit must be maintained in a readily retrievable format for a minimum of five years.	No EU# assigned	I did not review records for this equipment during this inspection.

Req. #	Pump-05 and Pump-07 Requirements	Emission Point	Inspector's Observations
12.	Excess emissions must be reported to SWCAA as follows: (a) As soon as possible, but no later than 12 hours after discovery for emissions that represent a potential threat to human health or safety; (b) As soon as possible, but no later than 48 hours after discovery for emissions which the permittee wishes to claim as unavoidable pursuant to SWCAA 400-107; and (c) No later than 30 days after the end of the month of discovery for all other excess emissions.	No EU# assigned	No excess emissions have been reported.
13.	Deviations from permit conditions must be reported no later than 30 days after the end of the month during which the deviation is discovered.	No EU# assigned	No deviations have been reported.
14.	The following emission-related information must be reported to SWCAA by March 15th for the previous calendar year: (a) The total number of hours the Pump-05 Engine and the Pump-07 Engine operated; and (b) Air emissions of criteria air pollutants, volatile organic compounds, toxic air pollutants (TAPs), and hazardous air pollutants (HAPs).	No EU# assigned	This information for 2024 was submitted with the annual emissions inventory.

Settlement Agreement Terms – TransAlta's Current and Future Requirements Related to Mercury (signed May 19 & 25, 2010) Note that these conditions are not part of the Air Operating Permit Program and are not federally enforceable. Ecology may terminate the Settlement Agreement if TransAlta does not meet the agreed terms. The terms are not enforceable by any other means.

Condition III(b)8 states "…The Early Mercury Reduction provisions of this Settlement Agreement will become null and void upon the effective date of a federal rule or of a state rule adopted to comply with a federal rule applicable to the Centralia Plant's mercury emissions." In a letter dated March 27, 2014 TransAlta indicated that the "effective date" of 40 CFR 63 Subpart UUUUU was the publication date of February 16, 2012 and therefore did not anticipate submitting additional reports. Note that the compliance date for Subpart UUUUU was April 16, 2015. It is SWCAA's understanding that the Settlement Agreement was referring to the "compliance date" so there would be no gaps in Hg control system operation. Subpart UUUUU is currently in effect in place of the settlement agreement.

Req. #	Coal Plant Requirements	Emission Point	Inspector's Observations
N/A	Beginning January 1, 2012, TransAlta will demonstrate a mercury removal efficiency of 50 percent of the mercury content of the coal fired in the boilers, or expend $3 million per year on operation and maintenance costs including, but not limited to, routine operations and maintenance, sorbent costs, byproduct disposal costs associated with mercury capture, and monitoring costs. TransAlta, in its sole discretion, will decide on the method for determining mercury removal efficiency after considering comments by Ecology and SWCAA.	EU-1, EU-2	Subpart UUUUU in effect in place of this requirement.
N/A	Beginning January 2009, TransAlta will monitor mercury emissions using a CEMS. On or before January 2012, the monitoring will comply with 40 CFR Parts 60 and 75 (as in effect for the CAMR).	EU-1, EU-2	Subpart UUUUU in effect in place of this requirement.
N/A	TransAlta will operate the sorbent injection or alternative technology on a continuous basis commencing January 1, 2012.	EU-1, EU-2	Subpart UUUUU in effect in place of this requirement.
N/A	TransAlta will submit annual reports to Ecology documenting compliance with cost or mercury removal efficiency requirements beginning March 31, 2013, for the year 2012.	EU-1, EU-2	Subpart UUUUU in effect in place of this requirement.

ENGROSSED SECOND SUBSTITUTE SENATE BILL 5769 "Coal Fired Electric Generation Facilities" (Signed into law April 29, 2011, Effective July 22, 2011)

Req. #	Coal Plant Requirements – SB 5769	Emission Point	Inspector's Observations
N/A	(i) A coal-fired baseload electric generation facility in Washington that emitted more than one million tons of greenhouse gases in any calendar year prior to 2008 must comply with the lower of the following greenhouse gas emissions performance standard such that one generating boiler is in compliance by December 31, 2020, and any other generating boiler is in compliance by December 31, 2025: (A) One thousand one hundred pounds of greenhouse gases per megawatt-hour; or (B) The average available greenhouse gas emissions output as determined under RCW 80.80.050. (ii) This subsection (3)(c) does not apply to a coal-fired baseload electric generating facility in the event the department determines as a requirement of state or federal law or regulation that selective catalytic reduction technology must be installed on any of its boilers. RCW 80.80.040(3)(c)	EU-1, EU-2	Requirements from RCW 80.80 are not "applicable requirements" for the purposes of the Title V program. These requirements will be enforced by Ecology. Unit 1 met this standard by shutting down December 31, 2020.
N/A	(1) By January 1, 2012, the governor on behalf of the state shall enter into a memorandum of agreement that takes effect on April 1, 2012, with the owners of a coal-fired baseload facility in Washington that emitted more than one million tons of greenhouse gases in any calendar year prior to 2008. The memorandum of agreement entered into by the governor may only contain provisions authorized in this section, except as provided under section 108 of this act. (2) The memorandum of agreement must: (a) Incorporate by reference RCW 80.80.040, 80.80.060, and 80.80.070 as of the effective date of this section; (b) Incorporate binding commitments to install selective noncatalytic reduction pollution control technology in any coal-fired generating boilers by January 1, 2013, after discussing the proper use of ammonia in this technology. To be added to RCW 80.80	EU-1, EU-2	MOA dated December 23, 2011. First Revision of Order No. 6426 was issued December 13, 2011, incorporating the relevant air quality requirements.

All of the applicable monitoring requirements for TransAlta Centralia Generation are listed below in the format of Air Operating Permit SW98-8-R5-A.

The permittee shall conduct each of the monitoring and recordkeeping activities listed below. All records required by this Permit must be kept for a minimum period of no less than five years and must be maintained in a form readily available for inspection by SWCAA representatives. [WAC 173-401-615(2)(c), 40 CFR 63.10(b)(1), 40 CFR 63.6660]

Pursuant to WAC 173-401-530(2)(c), none of the following monitoring or recordkeeping requirements apply to Insignificant Emission Units (IEUs).

M1. General Recordkeeping **WAC 173-401-615(2)**
ADP 97-2057R1 Sections 26, 29, and 42
ADP 05-2636 Condition 4
ADP 08-2779 Condition 4(b)
ADP 11-2972 Condition 15
ADP 14-3093 Condition 11(c)

Except for data recorded by an automated system, each record required by this Permit must include, at a minimum, the date and the name of the person making the record entry. For those records required for a control device or process, if the control device or process is not operating during a specific time period, a record must be made to that effect.

Permittee is required to keep the following records as applicable:

(a) Inspections and Certifications
  (1) Date and time of the inspection or certification;
  (2) Name and title of the person who conducted the inspection or certification;
  (3) Identification of the unit or activity being inspected or certified;
  (4) Operating conditions of the unit or the type of activity occurring at the time of the inspection or certification;
  (5) Compliance status of each monitored requirement as described in Sections VI and VII of this Permit; and
  (6) Description of corrective action (if any) taken in response to a discovered permit deviation, excess emission, upset condition, or malfunction, as applicable.

(b) Complaints
  (1) Date and time of complaint;
  (2) Name of the complainant;
  (3) Description of the complaint;
  (4) Date and time of follow-up inspection;
  (5) The name and title of the person who conducted the follow-up inspection; and
  (6) Description of corrective action (if any) taken in response to complaint.

(c) Sampling and Emissions Testing
  (1) Date sampling was performed;
  (2) Entity that performed the sampling;
  (3) Name and title of the person or the entity that performed the sampling or testing to include,

as a minimum for source emissions testing;
(i) Heat input into boiler (million Btu/hr) (EU-2);
(ii) Fuel consumption rate (lb/hr);
(iii) Air discharge flowrate (dry standard cubic feet);
(iv) Exhaust temperature of emissions out the stack; and
(v) Unit load on an hourly basis (megawatts);

(4) Analytical techniques used to take the sample;
(5) Operating conditions existing at the time of sampling or measurement;
(6) Date analytical analyses (if any) were performed;
(7) Entity that performed the analyses;
(8) Analytical techniques or methods used;
(9) Results of such analyses;
(10) Compliance status of each monitored requirement as described in Section VI and VII of this Permit; and
(11) Description of corrective action taken in response to permit deviations and when action was initiated.

(d) Periodic Monitoring and Emissions Records
(1) Date and time of parameter observation or emission calculation;
(2) Name of parameter observed or emission calculated;
(3) Observed parameter value or calculated emission value with appropriate units; and
(4) Periods that data was unavailable.

(e) Excess Emissions and Permit Deviations
(1) Date and time of excess emission or permit deviation occurred;
(2) Description of the excess emission or permit deviation and an identification of the affected unit, process, or activity; and
(3) Description of corrective action taken in response to a discovered permit deviation, excess emission, upset condition, or malfunction, as applicable.

(f) Maintenance Activities
(1) Date and time of the maintenance activity;
(2) Name of the person/company who performed the maintenance;
(3) Identification of the unit or activity being maintained; and
(4) Description of the maintenance being conducted.

(g) Changes at Source
(1) Date changes were made to the source that resulted in emissions of a regulated air pollutant but not otherwise regulated under the Permit;
(2) Description of the changes made to the source; and
(3) Quantity of emissions resulting from the changes.

(h) Upset Conditions

Coal Plant [ADP 97-2057R1 Sections 26 and 29]
(1) Equipment out of service and upset conditions that impact SO_2 emissions; and
(2) Any emissions bypass that is not monitored by a certified functional CEMS.

Coal Unloading Facility [ADP 11-2972 Condition 15(d)]
(3) Upset conditions that cause excess emissions from the coal unloading facility must be recorded for each occurrence.

FGD Bleed Treatment Lime Storage Silo [ADP 05-2636 Condition 4(c)]

(4) Upset conditions that cause excess emissions from the FGD Bleed Treatment Lime Storage Silo must be recorded for each occurrence.

Journal Shop [ADP 08-2779 Condition 4(b)]

(5) Upset conditions that cause excess emissions from the Journal Shop must be recorded for each occurrence.

Fine Coal Handling [ADP 14-3093 Condition 11(c)]

(6) Upset conditions that cause excess emissions from fine coal handling must be recorded for each occurrence.

A spot check of quarterly reports indicated proper documentation.

M2. Visible Emission Monitoring WAC 173-401-615(1) - (for EU-3)
SWCAA 97-2057R1 Section 36
SWCAA 01-2403 Section 11(c)
SWCAA 11-2984 Condition 7
SWCAA 14-3093 Condition 10

EU-1, EU2, and EU-3: At least 6 minutes of opacity observations must be conducted each calendar quarter for EU-1, EU-2, and EU-3 by a Certified Observer using the visible emissions evaluation method in Appendix A of this permit. [SWCAA 97-2057R1 § 36, and WAC 173-401-615(1)]

EU-4, EU-5, and EU-6: The permittee must perform monthly inspections of fly ash loading from the 6050 unloaders and Unit #1 and Unit #2 turbine lube oil mist eliminators during daylight hours to identify any evidence of visible emissions violations. The inspections must be conducted by an EPA Method 9 certified individual or someone educated in the procedures of visible emission evaluation. Inspection of the fly ash unloading must consist of a survey to determine the presence or absence of excessive opacity, excessive fugitive dust, or evidence of excess emissions. Inspection of the turbine lube oil mist eliminator stacks must consist of at least six minutes of opacity observations taken in accordance with SWCAA 400, Appendix A, Method 9. If conditions do not permit opacity readings, an opacity log sheet must be filled out with the weather and operating conditions noted. A reasonable attempt must be made to schedule opacity readings while weather conditions are favorable for the method (i.e. in a warm afternoon vs. a cool morning). For every reading in excess of the opacity standard, opacity must be read for an additional 6 minutes to a maximum total of 60 minutes or 13 readings in excess of the opacity standard, whichever is shorter. Whenever visible emissions in excess of the standard or excessive fugitive dust are observed during the monthly inspection, or any other time, the permittee must initiate corrective action within 2 hours of observing excess visible emissions. Whenever excess emissions are observed or evidenced, the permittee must identify the pertinent equipment and verify whether the equipment is or is not experiencing a malfunction and that all relevant air pollution control equipment is operating properly. [SWCAA 01-2403 § 11(c)]

EU-7, EU-11, EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21, and EU-22 and plantwide sources of fugitive dust: The permittee must perform monthly inspections of EU-7, EU-11, EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21, and EU-22 during daylight hours to identify and prevent potential emissions violations. Whenever fallout of

particulate matter beyond the permittee's property boundary, visible emissions in excess of the standard, or any other potential excess emissions are observed during the monthly inspection or any other time, the permittee must determine the source of the emissions. The permittee must initiate corrective action within 2 hours of observing the excess emissions. The permittee must determine whether the pertinent equipment is or is not experiencing a malfunction and whether all relevant air pollution control equipment is operating properly. Within 24 hours of initial discovery, the permittee must resolve the operational problem, or notify SWCAA by the next working day of progress made in resolving the operational problem. [SWCAA 01-2350R4 Condition 18 for EU-11,-SWCAA 11-2984 Condition 7 for EU-19 through EU-27]

Implementation of corrective action does not relieve the permittee from the obligation of reporting permit deviations as specified in WAC 173-401-615(3).

Documentation of all required monthly monitoring was submitted to SWCAA for the past year.

M3. Particulate Matter Emissions Monitoring **SWCAA 05-2636 Condition 3**
SWCAA 11-2972 Condition 14
SWCAA 12-3016 Condition 7
SWCAA 14-3093 Condition 6

WAC 173-401-615(1)

The Permittee must perform monthly inspections of emission units EU-2 through EU-6, and EU-8 during daylight hours to identify potential particulate matter emissions violations. All other emission units (EUs and IEUs) must be inspected if the specific unit is implicated by a complaint or if otherwise unusual emissions are observed. Whenever fallout of particulate matter beyond the Permittee's property boundary or visible emissions in excess of the standard are observed during the periodic inspection as required in M1, or any other time, the Permittee must determine the source of the emissions. The Permittee must initiate corrective action within 2 hours of observing particulate matter fallout or excess visible emissions. The Permittee must confirm whether the pertinent equipment is or is not experiencing a malfunction and whether all relevant air pollution control equipment is operating properly. Within 24 hours of initial discovery, the Permittee must resolve the particulate matter fallout or excess emissions or notify SWCAA by the next working day of progress made in resolving the operational problem.

Spray/fog nozzles in high pressure water spray systems at the Coal Unloading Facility must be visually inspected once per month when in operation to ensure proper function. Clogged or defective nozzles must be replaced or repaired prior to subsequent operation. The operating pressure of the water spray system must be measured during the monthly inspection.

Spray/fog nozzles in the wet suppression system(s) for the fine coal handling system must be visually inspected once per week when in operation to ensure proper function. Clogged or defective nozzles must be replaced or repaired prior to subsequent operation.

Monthly inspections were reported in the quarterly reports. No visible emissions, deviations, or fallout of particulate matter was indicated in the reports.

M4. Fugitive Emissions Monitoring **WAC 173-401-615(1)**
SWCAA 01-2403 Section 11(c)

The Permittee must perform monthly inspections of emission units EU-2 through EU-8 during daylight hours to identify any excess fugitive emissions including fugitive dust. All other emission units (EUs and IEUs) must be inspected if the specific unit is implicated by a complaint or if otherwise unusual emissions are observed. Inspection of the fly ash unloading must consist of a survey to determine the presence or absence of excessive opacity, excessive fugitive dust, or evidence of excess emissions. Whenever fugitive emissions including excessive fugitive dust are observed during the monthly inspection or any other time, the Permittee must determine the source of the emissions. The Permittee must within 2 hours of discovery initiate investigation of the equipment involved to confirm whether the equipment is or is not experiencing a malfunction, and whether reasonable precautions and good work practices are being employed to minimize emissions. For this requirement, reasonable precautions and good work practices include, but are not limited to, the following:

(a) Apply water and/or chemical dust suppressants to coal when received at the plant site and to coal entering conveyors or other process or transfer points daily when fugitive dust from coal handling operations is routinely observed to be 20% or higher opacity, or more frequently as necessary to minimize fugitive coal dust consistent with Req-8;
(b) Operate baghouse dust collectors at any shop where significant welding is conducted (e.g., Journal Shop); and
(c) Use a water truck to apply water to paved and unpaved traffic areas on a daily basis during periods when fugitive dust from these areas is routinely observed to be 20% opacity, or more frequently as necessary, to minimize fugitive road dust.

All required monitoring was reported in the quarterly reports.

M5. Complaint Monitoring **WAC 173-401-615(1)**
SWCAA 11-2984 Condition 9
SWCAA 12-3016 Condition 9

The Permittee must record, and maintain record of, any air quality related complaints received by either the Permittee or SWCAA. All complaints must be investigated no later than one workday after the Permittee has been notified, and those complaints subject to requirement M2 must be addressed in a timely manner consistent with M2. The Permittee must determine the validity of each complaint and the cause of any emissions that may have prompted the complaint, and initiate corrective action, if needed, in response to the complaint. Within 24 hours of notification and investigation, the Permittee must resolve the subject of the complaint, or notify SWCAA by the next working day of progress made in resolving the complaint.

No air quality complaints have been received by TransAlta or SWCAA in the past year related to this facility.

M6. Operations Monitoring **WAC 173-401-615(1)**

The Permittee must perform monthly inspections of emission units EU-2 through EU-8 during daylight hours to confirm that pollution control equipment is operating according to manufacturer specifications and/or consistent with good engineering and maintenance practices. All other emission units (EUs and IEUs) must be inspected if the specific unit is implicated by a complaint or if otherwise unusual emissions are observed. Whenever nonstandard conditions are observed during the monthly inspection or any other time, the Permittee must initiate corrective action within 2 hours of observing an equipment problem. The Permittee must determine whether the pertinent equipment is or is not experiencing a malfunction and whether all relevant air pollution control equipment is operating properly. The Permittee must review maintenance records as necessary to monitor the operations of air pollution control equipment. Within 24 hours of initial discovery, Permittee must resolve the operational deficiency, or notify SWCAA by the next working day of progress made in resolving the operating problem. Implementation of corrective action does not relieve the Permittee from the obligation of reporting permit deviations as specified in WAC 173-401-615(3).

All required monitoring was reported in the quarterly reports.

M7. Coal Plant SO_2 General Standard Monitoring
SWCAA 97-2057R1 Section 27(c) and 43(a)

This monitoring requirement applies to EU-2 and EU-3 only.

Monitoring to ensure compliance with Req-6 on a 60-minute average is described in M8. The Permittee must monitor, record, and maintain record of the sulfur content of coal combusted in the boiler of emission unit EU-2. This monitoring must include, at a minimum, the sulfur content determined on a monthly basis from analysis of composite coal samples. A linear relationship exists between coal sulfur content and unscrubbed SO_2 concentration with a sulfur content of approximately 1% by weight corresponding to an unscrubbed emission concentration of 1,000 ppm. Coal sulfur content must be used, as necessary, to verify SO_2 monitoring results required by M8. The Permittee must determine the sulfur content of the fuel oil used to fuel the auxiliary boiler (EU-3) and for startup of EU-2 at a sufficient frequency that allows the sulfur content to be certified in each quarterly report.

Fuel oil sulfur content was provided in each quarterly report. TransAlta conducted weekly coal sampling that included a sulfur analysis. Sulfur content results were all well below 1% in the past four quarters.

M8. Coal Plant Stack Sampling Monitoring Requirements

SWCAA 97-2057R1 Sections 35, 40, and 42
Second Revision of BART Order No. 6426 Condition 4.1 except 4.1.4
40 CFR 63 Subpart UUUUU Sections 63.10007 and 63.10030

CO, PM Monitoring [SWCAA 97-2057R1]

This monitoring requirement applies to EU-2 only.

The Permittee must conduct emissions testing of EU-2 at least once every year to quantify emissions of particulate matter and to validate the CO CEMS. A minimum of three test runs must be performed at a minimum of 500 MW gross to establish that collected data are representative of normal operation. The use of continuous monitors is acceptable as an alternative emissions sampling schedule. The following reference test methods from 40 CFR 60 Appendix A, or equivalent methods if approved in writing by SWCAA in advance, must be used for these emissions tests:

Pollutant:	CO	PM
EPA Test Method:	10	5 and 202

The carbon monoxide annual emission concentration must be determined by the arithmetic average of hourly plant operating CO data corrected to 7% O_2 as follows:

CO, dry @ 7% O_2 = [(20.9 - 7) / (20.9 - O_2%, dry)] * CO, dry @ actual O_2%

The CO concentrations must be validated once per year, for each stack (flue), by source testing and the plant CO data adjusted for bias based on the Method 10 results. A formal relative accuracy test audit is not required.

The particulate matter test method must be consistent with the SO_2 control technology selected and must be appropriate for the stack conditions (i.e., wet or dry stack). Only the filterable fraction (as measured by EPA Method 5) must be used for comparison with the permitted limit, however, the condensable portion must continue to be measured and reported for emission inventory purposes. The PM result must be corrected to 7% O_2.

Ammonia Monitoring [Second Revision of BART Order No. 6426 Condition 4.1 except 4.1.4]
The ammonia monitoring and recordkeeping requirements below apply in any calendar year in which urea is injected using the SNCR system.

Ammonia emissions for compliance must be monitored by means of periodic emissions testing utilizing Bay Area Air Quality Management District (BAAQMD) Method ST1B or Environmental Protection Agency Conditional Test Method 027 (CTM-027). The sampling point will be in the stack following the wet scrubber. Stack testing must occur on the following frequency:

(a) Testing must occur once each calendar year if the ammonia feed-rate exceeds 1.5 gallons per minute during that calendar year. Testing must be performed while the SNCR is in operation and the feed-rate is above 1.5 gallons per minute during testing, with no consecutive tests less than 80 or more than 110 calendar days apart.

(b) If two consecutive tests are each more than the ammonia limitation, then the testing frequency decreases to once every six calendar months, provided the nitrogen oxides emission limit is complied with during the test.

(c) If, after there are three consecutive tests less than the ammonia limitation, the next two consecutive tests are less than 50% of the ammonia emission limitation, then the testing frequency reduces to once annually, provided the nitrogen oxides emission limit is complied with during the tests.

Performance Testing for 40 CFR 63 Subpart UUUUU

Performance testing for PM must be conducted quarterly in accordance with M9 if the Permittee choses the quarterly testing option over the PM CEMS option.

The Permittee must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin. [40 CFR 63.9(e) as modified by 40 CFR 63 Subpart UUUUU Table 9, 40 CFR 63.10030(a), 40 CFR 63.10030(d)]

Upon request, the Permittee must make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of 40 CFR 63.10007. [40 CFR 63.10007(g)]

The CO and PM compliance testing was conducted in the 3rd quarter of 2025. The results of the PM testing indicate compliance with the relevant emission limits. CO testing consisted of a full RATA (TransAlta maintains a CO CEMS on the FGD stack). Filterable PM testing has been conducted for each operating quarter. Ammonia testing has not been conducted because use of the SNCR systems has been discontinued in place of a combustion optimization system and neural network on Unit 2. Ammonia sampling is required if SNCR operation resumes. The initial compliance demonstrations for Subpart UUUUU were submitted in a document dated October 13, 2015.

M9. Coal Plant Continuous Monitoring Provisions

40 CFR 63 Subpart UUUUU Sections 63.10000(c)(1)(iv), 63,10000(d), 63.10006, 63.10007, 63.10010, 63.10020, 63.10021, Table 3 and Table 5
40 CFR 75
WAC 173-401-615
SWCAA 400-105(4)(a) and (4)(e)
SWCAA 97-2057R1 Sections 21, 24, 26, 27a, 27b, 27c, 30, and 36
SWCAA 16-3202 Section 14
Second Revision of BART Order No.6426 Condition 5

This monitoring requirement applies to EU-2 only.

The Permittee must monitor opacity, SO_2, NO_X, Hg, filterable PM, diluent (CO_2 and/or O_2), moisture, and stack flow for EU-2 in accordance with the requirements listed below.

The Permittee must monitor and collect data to demonstrate continuous compliance with the 30-boiler

operating day Hg, SO_2, and PM emission limits from 40 CFR 63 Subpart UUUUU according to the requirements in 40 CFR 63.10020 and 40 CFR 63 Subpart UUUUU Table 3. 40 CFR 63.10020 requires that monitoring be conducted at all times with certain exceptions (e.g., calibration checks), that data from all time periods except certain excepted periods listed in 63.10020(c) be used to report emissions, and specifies that any failure to collect required data is a deviation from the monitoring requirements of 40 CFR 63 Subpart UUUUU. 40 CFR 63.10020, 63.10021(h), and Table 3 require that monitoring be conducted during startup and shutdown. [40 CFR 63.10020, 40 CFR 63.10021(h)(2), 40 CFR 63 Subpart UUUUU Table 3]

Opacity

(a) Opacity of emissions from EU-2 must be monitored in accordance with the requirements of 40 CFR 75.

(b) If moisture is present in the gas stream to the extent that it interferes with the COMS providing accurate opacity data, then visual observations using Method 9, as described in Appendix A to this permit, must be performed a minimum of once per quarter to demonstrate compliance. [SWCAA 97-2057R1 Section 36]

(c) The Permittee must reduce all opacity data to 6-minute averages calculated from 36 or more data points equally spaced over each 6-minute period. Opacity data recorded as 1-minute averages calculated from 6 or more data points equally spaced over each 1-minute period must also meet this monitoring requirement. [40 CFR 75.10(d)(2); 40 CFR 51 Appendix P; SWCAA 97-2057R1 Section 36; WAC 173-401-615(1)]

SO_2

(d) SO_2 emissions from EU-2 must be monitored in accordance with the requirements of 40 CFR 75. [40 CFR 75, 40 CFR 63.10010(f), SWCAA 97-2057R1 Section 27, SWCAA 16-3202 Section 14]

(e) For the purposes of demonstrating compliance with the SO_2 limits found in SWCAA 97-2057R1 and SWCAA 400 the following additional requirements apply:

(1) In addition to 40 CFR Part 75 requirements, the SO_2 CEMS with automated DAHS must also record the SO_2 concentration (ppm) corrected to 7% O_2, dry, consistent with SWCAA 400-050(4) with the use of an O_2 CEMS (consisting of an O_2 concentration monitor) with automated DAHS. The O_2 system measures and records O_2 concentration (%) in the stack gas discharged to the atmosphere in accordance with 40 CFR 75.13(c) and 40 CFR 75 Appendix F. The correction for SO_2 must use the following method:

SO_2, dry @ 7% O_2 = [(20.9 - 7) / (20.9 - O_2%, dry)] * SO_2, dry @ actual O_2%; [SWCAA 97-2057R1 Sections 21 and 27a, and SWCAA 400-040(6) and 400-050(4)]

(2) 40 CFR Part 75 provisions also apply to each CEMS and component thereof for measuring and recording fixed clock 1-hour averages of O_2 concentrations and SO_2 standard concentrations (dry, corrected to 7% O_2). [SWCAA 97-2057R1 Section 27a]

(3) Except for the purposes of 40 CFR 63 Subpart UUUUU, whenever a valid hour of SO_2 concentration and flow rate data have not been measured and recorded, the Permittee must provide substitute data in accordance with 40 CFR 75 Subpart D. When determining compliance with the SO_2 concentration standard of SWCAA 97-2057R1 Sections 21 and 22, and SWCAA 400-040(6) (dry @ 7% O_2) and the SO_2 annual emission standard of SWCAA 97-2057R1 Sections 18 and 20, alternative data may be used for missing data

periods. For monitor out-of-service periods of four hours or less in duration, the average of the hour before and the hour following a monitor out-of-service period, in accordance with 40 CFR 75.33(b)(1)(i) must be used. For monitor out-of-service periods greater than four hours, data from an on-line coal analyzer, any as-burned coal analyses conducted by the Permittee, and plant emission control system operating data must be evaluated. The data or combination of data that best represents actual emissions must be used to determine compliance with the SO_2 limitations. Stack source test data may be used, if available and the source test is conducted according to methods approved by SWCAA. [SWCAA 97-2057R1 Section 27c]

(4) The Permittee must maintain records of SO_2 rolling 12-month mass emissions (not recorded hourly), as measured and reported from the certified primary monitoring system(s), certified redundant or non-redundant back-up monitoring system(s), or other approved method(s) of emissions determination: [SWCAA 97-2057R1 Sections 24, 26, and 27b]
   (i) Tons of SO_2 emitted from all relevant stacks (including any emergency bypasses) for each rolling 12-month period; and
   (ii) All SO_2 emissions during startup, shut down, equipment out of service, and upset conditions must be recorded separately from normal operations.

(f) For the purposes of demonstrating compliance with the SO_2 emission limits from 40 CFR 63 Subpart UUUUU, the following additional requirements apply:
   (1) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values. For startup or shutdown hours the default electrical load and the diluent cap are available for use in the hourly SO_2 emission rate calculations, as described in 40 CFR 63.10007(f). Use a flag to identify each startup or shutdown hour and report a special code if the diluent cap or default electrical load is used to calculate the SO_2 emission rate for any of these hours. [40 CFR 63.10010(f)(4), 40 CFR 63.10021(h)(1)]
   (2) Calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid SO_2 emission rates in the preceding 30-boiler operating days. [40 CFR 63.10010(f)(3)]

<u>NO_X</u>

(g) NO_X emissions from each EU-2 be monitored in accordance with the requirements of 40 CFR 75.

(h) For the purposes of demonstrating compliance with the NO_X limits found in SWCAA 97-2057R1, the following additional requirements apply:
   (1) Whenever a valid hour of NO_X concentration and flow rate data have not been measured and recorded, the Permittee must provide substitute data in accordance with 40 CFR 75 Subpart D. Stack source test data may be used, if available and the source test is conducted according to methods approved by SWCAA. [SWCAA 97-2057R1 Section 27c]
   (2) The Permittee must maintain records of the hourly average NO_X emission rate (lb/million Btu, rounded to nearest hundredth) adjusted for bias if necessary as provided for in 40 CFR 75.24(d), for those hours when a unit's generating load is 360 MW gross or greater, both units averaged together. [SWCAA 97-2057R1 Section 30, WAC 173-401-615]

(i) Reserved

Mercury (Hg) – Note that TransAlta is also subject to off-permit Hg control and monitoring requirements from a settlement agreement with Washington State signed in May 2010.

(j) For the purposes of demonstrating compliance with the Hg emission limits from 40 CFR 63 Subpart UUUUU, the Permittee must install, certify, operate, maintain and quality assure the data from the Hg CEMS or Hg sorbent trap monitoring system in accordance with Appendix A of 40 CFR 63 Subpart UUUUU. The Permittee must calculate and record a 30-boiler operating day rolling average Hg emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid Hg emission rates in the preceding 30-boiler operating days. [40 CFR 63.10000(d), 40 CFR 63.10010(g), 40 CFR 63 Appendix A]

Filterable PM

(k) For the purposes of demonstrating compliance with the PM emission limits from 40 CFR 63 Subpart UUUUU, the Permittee must either install, certify, operate, maintain and quality assure the data from a PM CEMS or perform quarter testing as described below [40 CFR 63.1000(c)(1)(iv)]:

(1) PM CEMS Option

The CEMS must be operated in accordance with 40 CFR 63.10010(i) and 40 CFR 63 Subpart UUUUU Table 5. The Permittee must calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler operating hours. [40 CFR 63.10010(i) and 40 CFR 63 Subpart UUUUU Table 5]

(2) Quarterly Testing Option

Testing for filterable PM must be conducted in accordance with 40 CFR 63.10007 and Section 1 of 40 CFR 63 Subpart UUUUU Table 5. Tests must be conducted each calendar quarter except as provided by 40 CFR 63.10021(d)(1). 40 CFR 63.10021(d)(1) allows a performance test to be skipped in a quarter with less than 168 operating hours, except that a performance test must be conducted at least once every calendar year. [40 CFR 63.1000(c)(1)(iv), 40 CFR 63.10021(d)(1)]

At least 45 calendar days, measured from the test's end date, must separate performance tests conducted every quarter. [40 CFR 63.10006(f)(1)(i)]

A performance test must be conducted in the 4th quarter of a calendar year if the unit has skipped performance tests in the first 3 quarters of the calendar year. [40 CFR 63.10006(f)(2)]

If a unit misses a performance test deadline due to being inoperative and if 168 or more boiler operating hours occur in the next quarter, an additional performance test must be conducted in that quarter. At least 15 calendar days must separate two performance tests conducted in the same quarter. [40 CFR 63.10006(f)(3)]

A minimum of 1 dry standard cubic meter of stack gas must be collected for each run. The unit must be operated at maximum normal operating load during each performance test run. [40 CFR 63.10006(c), 63.10007(a)(2), 63.10007(b), 63.10021(d) and Section 1 of Table 2 and Section 1 of Table 5 of 40 CFR 63 Subpart UUUUU]

Diluent (O_2 and/or CO_2)

(l) CO_2 and/or O_2 in the exhaust from EU-2 must be monitored in accordance with the requirements of 40 CFR 75. [40 CFR 75, 40 CFR 63.10010(b) SWCAA 97-2057R1 Sections 27]

(m) For the purposes of demonstrating compliance with the SO_2, PM, and Hg emission limits from 40 CFR 63 Subpart UUUUU, the following additional requirements apply:

(1) Only quality-assured diluent (O_2 or CO_2) data may be used in emission calculations. The data substitution procedures of 40 CFR 75 must not be used. [40 CFR 63.10010(b)]

Stack Gas Moisture Content

(n) The moisture content of the exhaust from EU-2 must be monitored in accordance with the requirements of 40 CFR 75 as necessary to convert pollutant concentrations or stack flow measurements from the measured basis (wet or dry) to the necessary basis (wet or dry) for emission rate calculations or comparison with applicable emission limits. [40 CFR 75]

(o) For the purposes of demonstrating compliance with the SO_2, PM, and Hg emission limits from 40 CFR 63 Subpart UUUUU, the following additional requirements apply:

(1) If the Permittee is required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 2 of Subpart UUUUU, the Permittee must install, certify, operate, and maintain a moisture monitoring system in accordance with part 75 of this chapter. Alternatively, the Permittee may use appropriate fuel-specific default moisture values from 40 CFR 75.11(b) to estimate the moisture content of the stack gas. If a moisture monitoring system is utilized, the Permittee must not use substitute moisture data in the emissions calculations. [40 CFR 63.10010(d)]

Stack Flow

(p) Stack flow rate from EU-2 must be monitored in accordance with the requirements of 40 CFR 75. [40 CFR 75, 63.10010(c), SWCAA 97-2057R1 Section 27, SWCAA 16-3202 Section 14]

(q) For the purposes of demonstrating compliance with the SO_2, PM, and Hg emission limits from 40 CFR 63 Subpart UUUUU, the following additional requirements apply:

(1) If stack flow is used to convert pollutant concentrations to units of an electrical output-based emission standard from Subpart UUUUU, only unadjusted, quality-assured flow rate data may be used. Bias adjustment factors must not be applied to the flow rate data and substituted flow rate data must not be used in the calculations. [40 CFR 63.10010(c)]

General Monitoring Provisions Specific to 40 CFR 63 Subpart UUUUU

(r) CEMS for SO_2 and CEMS or sorbent trap monitoring systems for Hg must be installed in accordance with location requirements of 40 CFR 63.10010(a). [40 CFR 63.10010(a)]

(s) If a CEMS for SO_2 or Hg is not installed on the bypass stack of Unit 2, any operation through the affected bypass stack other than during startup or shutdown is a deviation from the

monitoring requirements of 40 CFR 63 Subpart UUUUU. If a PM CEMS is not installed, or quarterly testing for PM is not conducted on the bypass stack of Unit 2, any operation through the affected bypass stack other than during startup or shutdown is a deviation from the monitoring requirements of 40 CFR 63 Subpart UUUUU. [40 CFR 63.10006(c), 40 CFR 63.10010(a)(4)] (All deviations must be reported in the semiannual report).

(t) Except as otherwise provided in 40 CFR 63.10020(c), all quality-assured hourly data recorded by the SO_2, PM, and Hg CEMS and the other required monitoring systems (e.g. flow rate, CO_2, O_2, or moisture systems) must be used to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day rolling average basis, updated at the end of each new boiler operating day. The following equation must be used to determine the 30-boiler operating day rolling average: [40 CFR 63.10021(b), Section 1 of 40 CFR 63 Subpart UUUUU Table 7]

$$\text{Boiler operating day average} = \frac{\sum_{i=1}^{n} Her_i}{n}$$

Where:

Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30-boiler operating days.

(u) The Permittee must operate, maintain, and quality assure the SO_2, PM, and Hg CEMS in accordance with 40 CFR 63.8 except that the general duty clause to minimize emissions referenced to 40 CFR 63.6(e)(1) and requirements related to a written startup, shutdown, and malfunction plan do not apply. [40 CFR 63.8 and 40 CFR 63 Subpart UUUUU Table 9]

(v) The electrical output from Unit 2 must be recorded for each hour of operation. [WAC 173-401-615(1)]

(w) Submit notification to SWCAA of the date required SO_2 and Hg RATAs are scheduled to begin at least 60 calendar days before the RATA is scheduled to begin. [40 CFR 63.9(g)(1), 40 CFR 63.10030(a), 40 CFR 63 Subpart UUUUU Table 9]

All monitoring appears to have been conducted as required. TransAlta has chosen the quarterly source testing option for PM (allowed before July 6, 2027). TransAlta operates a sorbent trap monitoring system for Hg.

PM Test Dates

Quarter	Date Performed	Notes
3rd Quarter 2024	7/1/2025	M5/202
4th Quarter 2024	1/15/2025	M5 make-up test
1st Quarter 2025	3/25/2025	
2nd Quarter 2025	7/30/2025	M5 – 2nd Quarter make-up test
3rd Quarter 2025	9/16/2025	M5/202 – make-up test
4th Quarter 2025	11/4/2025	

M10. 40 CFR 63 Subpart UUUUU Recordkeeping and Startup Monitoring

40 CFR 63.8
40 CFR 63.10
40 CFR 63 Subpart UUUUU Sections 63.10000(m), 63.10020(e), 63.10032, 63.10033, and Table 9
WAC 173-401-615(2)

(a) The Permittee must generate and maintain the following records for Unit 2 (EU-2): [40 CFR 63.10032]

(1) A copy of each notification and report submitted to comply with 40 CFR 63 Subpart UUUUU, including all documentation supporting any Initial Notification or Notification of Compliance Status or compliance report submitted according to the requirements of 40 CFR 63.10(b)(2)(xiv). [40 CFR 63.10032(a)]
(2) Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required by 40 CFR 63.10(b)(2)(viii). The applicable reports referenced in 40 CFR 63.10(b)(2)(viii) are performance tests and continuous monitoring system evaluations (e.g., RATAs).
(3) The following records regarding PM, Hg, and SO_2 CEMS: [40 CFR 63.10032(b)]
  (i) Each period during which a continuous monitoring system was malfunctioning or inoperative (including out-of-control periods).
  (ii) All required measurements needed to demonstrate compliance with the requirements of 40 CFR 63 Subpart UUUUU as described in 40 CFR 63.10(b)(2)(vii).
  (iii) All measurements as may be necessary to determine the conditions of performance tests and performance evaluations.
  (iv) All CEMS calibration check results.
  (v) All adjustments and maintenance performed on the CEMS.
(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period. [40 CFR 63.10032(b)(4)]
(5) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3). [40 CFR 63.10032(b)(2)]
(6) Records of PM performance test reports, tune-up reports, startup and shutdown work practice standard monitoring, and all monitoring data and calculated averages for the SO_2 CEMS and Hg sorbent trap monitoring system. [40 CFR 63.10032(c)]
(7) Identification of the type and amount of each fuel combusted. [40 CFR 63.10032(d)(1)]
(8) Regarding startup periods or shutdown periods: [40 CFR 63.10000(m), 40 CFR 63.10032(f)]
  (i) Records of occurrence and duration of each startup and/or shutdown;
  (ii) Records of the determination of the maximum clean fuel capacity;
  (iii) Records of the determination of the maximum hourly clean fuel heat input and of the hourly clean fuel heat input; and
  (iv) Records of the information required in 40 CFR 63.10020(e). 40 CFR 63.10020(e) requires that the following information be recorded for each startup and shutdown period: [40 CFR 63.10020(e)]

a. The date and time that clean fuels being combusted for the purposes of startup and shutdown begins. [40 CFR 63.10020(e)(1)(i). 63.10020(e)(2)(i)]
b. The quantity and heat input of clean fuel for each hour of startup and shutdown. [40 CFR 63.10020(e)(1)(ii), 63.10020(e)(2)(ii)]
c. The gross output for each hour of startup and shutdown. [40 CFR 63.10020(e)(1)(iii), 63.10020(e)(2)(iii)]
d. The date and time that non-clean fuel combustion begins for each startup and ends for each shutdown. [40 CFR 63.10020(e)(1)(iv), 63.10020(e)(2)(iv)]
e. The date and time that clean fuels being combusted for the purpose of startup and shutdown ends for each startup and shutdown. [40 CFR 63.10020(e)(1)(v), 63.10020(e)(2)(v)]
f. The temperature and combustion air flow or calculated flow as determined from combustion equations of post-combustion (exhaust) gas, as well as amperage of forced draft fan(s) upstream of the filterable PM control devices during each hour of startup. [40 CFR 63.10020(e)(3)(i)(A)]
g. The temperature and flow rate of exhaust gas and amperage of induced draft fan(s) downstream of each filterable control device during each hour of startup. [40 CFR 63.10020(e)(3)(i)(B)]
h. The number of ESP fields in service, as well as each field's secondary voltage and secondary current during each hour of startup. [40 CFR 63.10020(e)(3)(i)(C)]

For the monitoring systems used to provide the data listed above, the Permittee must install, verify, operate, maintain, and quality assure each monitoring system and develop a site-specific monitoring plan for work practice monitoring during startup periods. The site-specific monitoring plan must be developed in accordance with the requirements listed in 40 CFR 63.10010(l). The Permittee must submit the site-specific monitoring plan upon request by SWCAA. [40 CFR 63.10010(l)]

During startup periods, the Permittee must monitor and collect data according to this section and the site-specific monitoring plan required by 40 CFR 63.10010(l). [40 CFR 63.10020(e)(3)]

(9) Records of the occurrence and duration of each malfunction of an operation (*i.e.*, process equipment) or the air pollution control and monitoring equipment. [40 CFR 63.10032(g)]
(10) Records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. [40 CFR 63.10032(h)]
(11) Records of the type(s) and amount(s) of fuel used during each startup or shutdown. [40 CFR 63.10032(i)]

(b) The Permittee must generate and maintain the records required by the sections of 40 CFR 63.10 listed in 40 CFR 63 Subpart UUUUU Table 9 for Unit 2 (EU-2). These records include, but are not limited to: [40 CFR 63 Subpart UUUUU Table 9]

(1) All required maintenance of CEMS and pollution control equipment.
(2) All CEMS data.
(3) Identification of all time periods when a CEMS was inoperative except for zero and span checks.
(4) Identification of all time periods when a CEMS was out of control.
(5) Identification of each period of excess emissions.
(6) The nature and cause of any malfunction.
(7) The corrective action taken or preventive measures adopted.
(8) The nature of the repairs or adjustments to CEMS that were inoperative or out of control.
(9) All procedures that are part of a quality control program developed and implemented for the CEMS under 40 CFR 63.8(d).

The records must be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). The records must be maintained for five years following the date of each occurrence, measurement, maintenance, corrective action, report or record. Each record must be kept on site, or they must be accessible from on site, for at least five years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. [40 CFR 63.10033]

Most of these records are submitted to SWCAA quarterly. I did not find any missing elements during spot checks of applicable records.

M11. Coal Plant Startup, Shut Down, and Outage Operation Procedures for RACT Order SWCAA 97-2057R1 Sections 21b, 23, 25, 26, 28e, 37, and 38

This monitoring requirement applies to EU-2 only.

During startup and shutdown of EU-2, emissions control equipment must be operated to minimize overall emissions, except to the extent equipment operation will cause degradation of its long-term performance. Opacity exceedances during manual ESP rapping and boiler chemical cleaning are excused under SWCAA 400-107(2)(d). Exceedances of the PM and opacity limitations are excused under SWCAA 400-107 during unit startup and shutdown when the ESPs are out of service. Exceedances of the normal operation hourly SO_2 limitation (250 ppmvd @ 7% O_2), are excused under SWCAA 400-107 during startup and shutdown when the ESPs and SO_2 emission control technology are out of service, provided the alternative SO_2 emission limits of Req-19 are met. The shutdown period begins when the ESP temperature drops to 220°F, when the SO_2 emission control technology and then the ESPs are taken out of service. The startup period begins when fuel is introduced into a boiler to raise its temperature to operating conditions. The startup period ends when the earlier of the two operating events below occurs:

(a) Opacity in the gas path downstream of both ESPs has stabilized below 10% for 30 minutes; or
(b) 8 hours have elapsed after the startup unit is synchronized electrically on-line.

During SO_2 emission control technology outages and upsets, emissions in excess of the hourly SO_2

limitation are excused provided they satisfy the alternative SO_2 emission limits of Req-19 or they meet the burden of proof regarding unavoidable emissions in accordance with SWCAA 400-107. The Permittee must demonstrate that a forced outage of the SO_2 emission control technology while the unit operates is managed to minimize emissions. Implementation of corrective action does not relieve the Permittee from the obligation of reporting permit deviations as specified in WAC 173-401-615(3).

TransAlta reports details of each startup and shutdown event, including when the generator was synchronized electrically on-line. No violations of this requirement have been reported in the past year. In the last half of 2024 the ESPs were fully engaged no later than 7 minutes after firing coal. During 2025, the ESPs were fully engaged by the time coal was fired. The ESPs have been operated for some time after coal firing has ceased on shutdown. This is necessary because fly ash continues to make it's way out of the boiler and ductwork for a period of time after coal combustion has ceased.

M12. Coal Plant SO_2 12-Month Period Emission Evaluation SWCAA 97-2057R1 Sections 26, 28c, and 28d

This monitoring requirement applies to EU-2, and EU-3 only.

All hourly SO_2 emission data for startup, shutdown, upset and forced or planned emission control system outage periods must be included in the calculations of the annual tons of SO_2 emitted. For periods when all fuel is out of a boiler, SO_2 emissions for that unit must be assumed to be zero. An exceedance of the annual limitation is one 12-month period exceeding the tons/year SO_2 limitation as defined in Req-17. Each exceedance of the rolling 12-month emission limitation, except as excused under SWCAA 400-107, will constitute a continuing violation for the days in the last month of the 12-month period. Each day of violation must be treated equally and be subject to penalty as allowed by law at the time of the non-compliance. The Permittee may calculate 365-day emission summations ending on each day in the last month of the 12-month period to reduce the number of violation days subject to penalty. If adequately demonstrated, the number of violation days must not include the number of 365-day periods ending within the last month of the exceedance period for which the emissions summation did not exceed the annual limit.

TransAlta has met the 12-month rolling total SO_2 limitation beginning April 1, 2003.

M13. Coal Plant SO_2 Monitoring of Bypass Stack SWCAA 97-2057R1 Section 29

This monitoring requirement applies to EU-2 only.

Any bypass through the bypass stack that is not monitored by a certified functional CEMS for SO_2 is considered an upset condition and must be reported consistent with requirement R1. All SO_2 emissions discharged from the bypass stack must be included in the calculation of emissions for determining compliance with the annual limit.

SO_2 CEMS are installed in the ductwork upstream of the diversions to the bypass stacks to monitor SO_2 emissions from the bypass stacks. TransAlta totals emissions from both the bypass

and FGD stacks for each unit and reports this data in the quarterly reports. The SO_2 CEMS passed its most recent relative accuracy test audit in August 2025.

M14. Coal Plant Fuel Oil Usage Evaluation **40 CFR 63.7525(k)**
SWCAA 97-2057R1 Sections 43 and 45

The Permittee must monitor fuel oil usage in the boilers at the Coal Plant (EU-2, and EU-3). The Auxiliary Boiler (EU-3) must have a separate fuel meter to monitor the total amount of fuel consumed in that boiler. Emissions of SO_2 from the Auxiliary Boiler must be included when evaluating the 10,000 tons per year emission limit in Req-17. Emissions must be calculated based on fuel consumption and fuel sulfur content. [SWCAA 97-2057R1 Sections 43 and 45]

The amount of fuel oil used in the Auxiliary Boiler must be recorded for each day of operation. [40 CFR 63.7525(k)]

EU-3 is equipped with a separate fuel meter (totalizer). Emissions of SO_2 from the auxiliary boiler are relatively low (0.02 tons in 2025) because only ultra-low sulfur diesel is burned. Fuel consumption for each unit was reported in each quarterly report.

M15. Reserved

M16. Reserved

M17. Reserved

M18. Reserved

M19. Maintenance Activities Monitoring **40 CFR 63.6655(e)**
SWCAA 01-2403 Section 11(c)

This monitoring requirement applies to EU-4 and EU-6 only.

The Permittee must document each occurrence of maintenance and repairs to the fly ash unloading pugmill and turbine lube oil mist eliminator that may affect emissions.

No maintenance activities with the potential to affect emissions have been reported in the past year for the turbine lube oil mist eliminator. No evidence of major maintenance was apparent during the inspection. The fly ash unloading pugmill is not in regular use.

M20. Particulate Matter Compliance Assurance Monitoring for BW22

40 CFR 64
WAC 173-401-615(4)

This monitoring requirement applies to EU-2 only.

This monitoring requirement applies unless a particulate matter continuous emissions monitoring system is installed and certified in accordance with the requirements of 40 CFR 63 Subpart UUUUU.

In addition to the opacity monitoring requirements of Requirement 13 and M8, the Permittee must continuously monitor opacity in the ductwork upstream of the bypass stack in accordance with the quality assurance and quality control requirements of 40 CFR 75 except that the existing monitoring locations immediately upstream of the bypass stack are acceptable. The COMS must provide for at least 90% data availability (annual average rolled monthly).

Opacity less than the following is indicative of proper operation of the ESPs and provides a reasonable assurance of compliance with the particulate matter emission limits:

Exhaust Point	Maximum Opacity[1]
EU-2 Bypass Stack	20% (1-hour average)
EU-2 FGD Stack	30% (1-hour average)

[1] This range does not apply during the defined startup and shutdown periods, during planned maintenance or outage periods, load changes, and during manual rapping of the ESP. The 1-hour average applies to the clock hour recorded by the COMS. An hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) if data are unavailable as a result of the performance of calibration, quality assurance, or preventive maintenance activities.

If opacity is measured in two ducts for the same emission unit, the arithmetic average of the opacity measurements from each duct must be used to compare with the maximum opacity listed above.

An excursion is defined as any exceedance of the maximum opacity levels identified in the table above. For each excursion:

(a) Inspect electrostatic precipitators within four hours. Report ESP field settings and a list of fields out of service.
(b) If the exceedance occurs during FGD operation, inspect FGD system for proper operation (excess inlet particulate loading can affect FGD performance) within four hours. Report the numbers of spray headers in service.
(c) Make necessary repairs as soon as practical.
(d) Restore opacity levels to less than the maximum levels indicated above as expeditiously as practical in accordance with good air pollution control practices for minimizing emissions.
(e) Notify SWCAA no later than the end of the next business day in accordance with R1.

No excursions have been reported during the past year and these standards were being met during the inspection (average opacity of 26.8% at the EU-2 FGD stack inlet).

M21. Coal Unloading Facility **SWCAA 11-2972 Condition 15(a)**

This monitoring requirement applies to EU-4 only.

The Permittee must develop and maintain the following information for the Coal Unloading Facility:

(a) The total amount of coal unloaded each calendar year.

This information was reported for calendar year 2024 with the annual emissions inventory.

M22. FGD Bleed Treatment Lime Storage Silo
SWCAA 05-2636 Condition 4(a) and 4(b)

This monitoring requirement applies to EU-4 only.

The Permittee must develop and maintain the following information for the FGD Bleed Treatment Lime Storage Silo:

(a) The total number of hours the FGD Bleed Treatment Lime Storage Silo dust collector is actively vented must be recorded for each calendar year; and
(b) The differential pressure across the FGD Bleed Treatment Lime Storage Silo dust collector must be recorded once per calendar month during loading.

The differential pressures and hour-meter readings have been included in the quarterly reports for each loading event. Differential pressures recorded in the past year ranged from 0.5" to 1" w.c.

M23. Journal Shop **SWCAA 08-2779 Condition 4(a)**

This monitoring requirement applies to EU-8 only.

The Permittee must develop and maintain the following information for the Journal Shop:

(a) The total amount of each welding rod type used in the Journal Shop must be recorded for each calendar year.

Welding rod usage for 2024 was reported with the annual emission inventory and used to calculate annual emissions.

M24. Reserved

M25. SNCR System Monitoring **WAC 173-401-615(1)**

This monitoring requirement applies to EU-2 only.

The Permittee must continuously monitor and record the following parameters related to operation of the SNCR system for each hour of operation:

The urea concentration and flow rate.

There was no urea injection in the past year. The requirement to inject urea has been removed in the latest version of the BART Order.

M26. Coal Plant Emergency Engine Monitoring **40 CFR 63.6655**
40 CFR 60.4214(b)
WAC 173-615(1)
SWCAA 400-075
SWCAA 400-115
SWCAA 16-3188 Condition 8

This monitoring requirement applies to EU-9 and EU-10 only.

The Permittee must conduct the following monitoring for EU-9 and EU-10:

(a) The Permittee must document and record each incidence of maintenance, maintenance checks, and repairs conducted to demonstrate compliance with the emissions-related maintenance requirements. Required maintenance activities are identified in Appendix C – Small Engine Maintenance Plan for Emergency Diesel Generator 1 (EU-9). [40 CFR 63.6655(e)]
(b) The number of hours Emergency Diesel Generator 1 and Emergency Diesel Generator 2 are operated each calendar year must be recorded from the non-resettable hour meter. The Permittee must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours were spent for non-emergency operation. [40 CFR 63.6655(f), 40 CFR 60.4214(b), SWCAA 16-3188 Condition 8(b)]
(c) The sulfur content of the diesel burned in Emergency Diesel Generator 1 and Emergency Diesel Generator 2 must be determined and recorded for each fuel delivery. A fuel supplier certification or receipt may be used in lieu of new fuel testing. [SWCAA 16-3188 Condition 8(a)]
(d) For the Emergency Diesel Generator 2 (EU-10), the Permittee must document and record each incidence of maintenance and repairs conducted to demonstrate compliance with the emissions-related maintenance requirements of 40 CFR 60.4211(a). The documentation must include a description of the maintenance and/or repair conducted and the hour meter reading on the engine at the time of the maintenance. [WAC 173-401-615(1)]

(a) I have requested maintenance records for these units.
(b) The operating hours were provided with the annual emissions inventory report.
(c) TransAlta provides a certification with each quarterly report that only ultra-low sulfur fuel is purchased.
(d) I have requested maintenance records for these units.

M27. Fire Pump Engine Monitoring **WAC 173-401-615(1)**
SWCAA 16-3188 Conditions 8(a) and 8(b)

This monitoring requirement applies to EU-11 only.

The Permittee must conduct the following monitoring for the Fire Pump Engine:

(a) The fuel sulfur content of the diesel burned in the Fire Pump Engine must be determined and recorded for each fuel delivery. A fuel supplier certification or receipt may be used in lieu of new fuel testing. [SWCAA 16-3188 Condition 8(a)]
(b) The Permittee must document the total number of hours the Fire Pump Engine operates each year. [SWCAA 16-3188 Condition 8(b)]
(c) For the Fire Pump Engine (EU-11), the Permittee must document and record each incidence of maintenance and repairs conducted to demonstrate compliance with the emissions-related maintenance requirements of 40 CFR 60.4211(a). The documentation must include a description of the maintenance and/or repair conducted and the hour meter reading on the engine at the time of the maintenance. [WAC 173-401-615(1)]

(a) Only one grade of fuel is used at TransAlta for all equipment. The sulfur content has been documented by certification from the refinery and/or the fuel receipt. Only ultra-low sulfur fuel has been purchased in the past few years.
(b) Hours of operation were reported in the annual emissions inventory report.
(c) I have requested maintenance records for this unit.

M28. Coal Unloading Facility Emergency Diesel Sump Pump Engine Monitoring
40 CFR 60.4211(a)
WAC 173-401-615(1)
SWCAA 11-2972 Conditions 15(b and c)

This monitoring requirement applies to EU-12 only.

(a) The fuel sulfur content of the diesel burned in the Coal Unloading Facility Emergency Diesel Sump Pump Engine must be determined and recorded for each fuel delivery. A fuel supplier certification may be used in lieu of actual fuel testing. [SWCAA 11-2972 Condition 15(b)]
(b) The Permittee must document the total number of hours the Coal Unloading Facility Emergency Diesel Sump Pump Engine operates each year using the non-resettable hour meter. [SWCAA 11-2972 Condition 15(c)]

(c) The Permittee must document and record each incidence of maintenance and repairs conducted to demonstrate compliance with the emissions-related maintenance requirements of 40 CFR 60.4211(a). The documentation must include a description of the maintenance and/or repair conducted and the hour meter reading on the engine. [WAC 173-401-615(1)]

(a) Only one grade of fuel is used at TransAlta for all equipment. The sulfur content has been documented by certification from the refinery and/or the fuel receipt. Only ultra-low sulfur fuel has been purchased in the past few years.
(b) 5.7 hours of operation were reported for 2024.
(c) I have requested a sample of recent maintenance records for this engine.

M29. Mercury Control System and Fly Ash Material Handling

SWCAA 11-2984 Condition 8
SWCAA 12-3016 Condition 8

This monitoring requirement applies to EU-4, EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, and EU-21 only.

The Permittee must conduct the monitoring indicated below for EU-13 through EU-21:

(a) The total number of hours each emission unit associated with the mercury control project (SEA System 1, SEA System 2, Sorbent Silo 1, Sorbent Silo 2, Fly Ash Bin 11, Fly Ash Bin 12, Fly Ash Bin 14, Fly Ash Bin 14 Air Slide to Bin 11 Air Slide, Fly Ash Bin 14 to 6050 Air Slide) and the Fly Ash Weigh Bin is vented must be determined and logged for each calendar year.
(b) The output of each baghouse leak detection system installed on the exhausts of Fly Ash Bin 11, Fly Ash Bin 12, and Fly Ash Bin 14 must be logged continuously.
(c) Copies of operating and maintenance manuals for the pollution control equipment on SEA System 1, SEA System 2, Sorbent Silo 1, Sorbent Silo 2, Fly Ash Bin 11, Fly Ash Bin 12, Fly Ash Bin 14, Fly Ash Bin 14 Air Slide to Bin 11 Air Slide, Fly Ash Bin 14 to 6050 Air Slide, and the Fly Ash Weigh Bin must be maintained for reference purposes.
(d) Maintenance activities (including filter replacements) that may affect emissions from SEA System 1, SEA System 2, Sorbent Silo 1, Sorbent Silo 2, Fly Ash Bin 11, Fly Ash Bin 12, Fly Ash Bin 14, Fly Ash Bin 14 Air Slide to Bin 11 Air Slide, Fly Ash Bin 14 to 6050 Air Slide, and Fly Ash Weigh Bin must be logged for each occurrence.

(a) Hours of operation were reported with the annual emissions inventory report. Bin 14 and associated air slides did not operate in 2024 and remain out of service.
(b) I did not review the data output or logging during this inspection. The leak detector probes were installed and the units were operating with no visible emissions or sign of past emissions.
(c) During a past inspection Mr. Tim Weber provided a list of all maintenance manuals available for this equipment and indicated most were in Adobe PDF format. I did not review these records during this inspection. These records would typically be reviewed in response to an upset or excess emission event.

(d) These units appeared in good repair. Differential pressure on each unit was at 3" w.c. (the cleaning setpoint). I did not review maintenance records during this inspection.

M30. Fly Ash Baghouses - Source Emission Testing Requirements
SWCAA 11-2984 Conditions 12, 13, and Appendix A

This monitoring requirement applies to EU-17, EU-18, and EU-19 only.

Source emissions testing of the Fly Ash Bin 11 Baghouse, Fly Ash Bin 12 Baghouse, and Fly Ash Bin 14 Baghouse must be conducted as described below. Initial source emissions testing of each baghouse was conducted in October 2011. Subsequent source emissions testing must be conducted no later than the end of October every 5 years following the initial source emissions test. Source emissions tests conducted more than three months before the required due date will not satisfy the periodic source emission testing requirement without prior approval from SWCAA.

Testing for each constituent must consist of a minimum of three sampling runs of the duration specified below.

Constituent	Test Method or Equivalent[1]	Minimum Test Duration
Stack gas velocity, flow rate	EPA Methods 1 and 2	N/A
Stack gas dry molecular weight	EPA Method 3A (may assume ambient O_2 and CO_2 concentrations)	60 minutes
Stack gas moisture content	EPA Method 4	60 minutes
Particulate matter	EPA Method 5 or 17	60 minutes
Visible emissions	SWCAA Method 9	6 minutes

[1] The use of an alternate or equivalent test method must be pre-approved by SWCAA in writing.

A comprehensive test plan must be submitted to SWCAA for review and approval at least 10 business days prior to testing.

SWCAA personnel must be notified of the test date at least 5 days prior to the testing campaign so that they may be present during testing.

A complete record of operational parameters applicable to the testing, including but not limited to the operating status of the units being vented to the baghouse, leak detection system output, startups, and shutdowns must be kept during emissions testing to correlate operations with emissions and must be recorded in the final report of the test results.

Source operations during emissions testing must be representative of maximum intended operating conditions.

Source emissions testing of the baghouses for Bins 11 and 12 was most recently conducted September 14th and 16th, 2021. The Bin 14 Baghouse was not tested because it was, and remains, out of service.

M31. Fly Ash Bin Baghouses – Compliance Assurance Monitoring **40 CFR 64**
WAC 173-401-615(4)

This monitoring requirement applies to EU-17, EU-18 and EU-19 only.

In addition to the source emissions testing requirements of M33, the Permittee must utilize an Electrostatic Particle Detection (EPD) system to continuously monitor relative particulate matter concentration in the exhaust from the Fly Ash Bin 11 Baghouse, Fly Ash Bin 12 Baghouse, and Fly Ash Bin 14 baghouse.

The EPD system must provide for at least 90% data availability (annual average rolled monthly).

An EPD system output of less than the following alarm setpoints is indicative of proper operation of the baghouses and provides a reasonable assurance of compliance with the particulate matter emission limits:

Exhaust Point	Alarm Setpoint
Fly Ash Bin 11 Baghouse (EU-17)	100 pA (5-minute average)
Fly Ash Bin 12 Baghouse (EU-18)	100 pA (5-minute average)
Fly Ash Bin 14 Baghouse (EU-19)	100 pA (5-minute average)

An excursion is defined as any exceedance of the maximum output levels identified in the table above. For each excursion:
(a) Cease operation of the affected baghouse as soon as practicable and operate only as necessary to effectuate trouble-shooting and repairs.
(b) Make necessary repairs as soon as practical.
(c) Notify SWCAA no later than the end of the next business day in accordance with R1.

Alarm setpoints may be modified based on the results of additional source emissions testing when the Permittee can demonstrate that the new alarm setpoint provides a reasonable margin of compliance with the particulate matter emission limit.

The leak detectors are installed. No excursions have been reported.

M32. Reserved

M33. Coal-Fired Boiler Tune-up and Startup/Shutdown Monitoring
40 CFR 63.10000(l, m)
40 CFR 63.10032(a)(1)
40 CFR 63.10032(f)

This monitoring requirement applies to EU-2 only.

(a) To demonstrate compliance with the tune-up requirements in 40 CFR 63 Subpart UUUUU, the Permittee must document and keep records of each tune-up of EU-2. The records must document the date of each tune-up, all activities performed as part of the tune-up, and the results of NO_X, CO, and O_2 monitoring conducted as part of the tune-up. [40 CFR 63.10032(a)(1)]
(b) To demonstrate compliance with the provisions related to startup and shutdown in 40 CFR 63 Subpart UUUUU, the Permittee must continuously monitor and record the following for EU-2) beginning April 16, 2015: [40 CFR 63.10000(l)]
    (1) Distillate oil consumption;
    (2) Coal consumption;
    (3) Electricity generation;
    (4) When steam generated by the boiler is in use for any purpose; and
    (5) Operational status of each electrostatic precipitator, mercury emission control system, and flue gas desulfurization system.

    The equipment used to monitor these parameters must be verified, operated, maintained, and quality assured. Monitoring system specifications or instruction or manufacturer's specifications may be relied upon to meet these requirements. [40 CFR 63.10000(m)]

With the burner inspection conducted during the spring/summer 2016 outage, the initial tune-up has been completed. The second tune-up was comprised of actions completed between January 2017 and September 2018, with a report submitted in October 2018. The third tune-up (conducted in 2022) was completed, and a final report received by SWCAA October 7, 2022. No further tune-ups are due before the unit retires. Much of the information in (b) is reported for startups as either time of start/stop or hourly values. All of this information is available electronically.

M34. Auxiliary Boiler Tune-up Monitoring **40 CFR 63.7555, 63.7560 WAC 173-401-615(b)(2)**

The Permittee must conduct the following monitoring and recordkeeping for the Auxiliary Boiler (EU-3):

(a) The Permittee must document and keep records of each tune-up of EU-3. The records must document the date of each tune-up, all activities performed as part of the tune-up, and the results of NO_X, CO, and O_2 monitoring conducted as part of the tune-up. [40 CFR 63.7555(a)(1) (initial tune-up), WAC 173-615(b)(2) – (subsequent tune-ups)]
(b) The Permittee must maintain a copy of each notification and report submitted to comply with 40 CFR 63 Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or compliance report submitted according to the requirements of 40 CFR 63.10(b)(2)(xiv); [40 CFR 63.7555(a)(1)] and
(c) The Permittee must maintain a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the Auxiliary Boiler was operating. [40 CFR 63.7555(a)(3)]

The records must be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). The records must be maintained for five years following the date of each

occurrence, measurement, maintenance, corrective action, report or record. Each record must be kept on site, or they must be accessible from on site, for at least two years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. The Permittee may keep the records off site for the remaining three years. [40 CFR 63.7560]

The initial tune-up was conducted January 29, 2016. The subsequent tune-up was due February 2021 and was reportedly completed in January 2021, but a report was never submitted to TransAlta by the contractor. The tune-up was officially completed in May 2022 after SWCAA issued NOV 10123 and TransAlta subsequently completed repairs of the unit.

M35. Fine Coal Handling 40 CFR 60 Subpart Y Sections 60.255, 60.257, and 60.258(a)
SWCAA 14-3039 Condition 11(b)

The fine coal recovery process was retired effective June 30, 2021. All fine coal processing equipment has been removed.

M36. Acid Rain, RACT, and NSR CEMS Data Recordkeeping Requirements
40 CFR 75.57, 75.58, and 75.59
WAC 173-401-615(2)
SWCAA 97-2057R1 Sections 24, 26, 27 and 30

The Permittee must record and maintain for EU-2, a file of all measurements, data, reports, and other information required by this permit at the source in a readily accessible form suitable for inspection for at least five (5) years from the date of each record. This file must include all information required in 40 CFR Part 75.57 through 75.59 with the following:

(a) SO_2 standard concentrations (dry @ 7% O_2) required by condition M8 of this permit. [SWCAA 97-2057R1 Section 27]

(b) For SO_2 rolling 12-month mass emissions (not recorded hourly), as measured and reported from the certified primary monitoring system(s), certified redundant or non-redundant back-up monitoring system(s), or other approved method(s) of emissions determination: [SWCAA 97-2057R1 Sections 24, 26, and 27b]
  (1) Tons of SO_2 emitted from all relevant stacks (including any emergency bypasses) for each rolling 12-month period; and
  (2) All SO_2 emissions during startup, shut down, equipment out of service, and upset conditions must be recorded separately from normal operations.

(c) Hourly average NO_X emission rate (lb/million Btu, rounded to nearest hundredth) adjusted for bias if necessary as provided for in 40 CFR 75.24(d), for those hours when the unit's generating load is 360 MW gross or greater. [SWCAA 97-2057R1 Section 30, WAC 173-401-615]

All hourly data has been submitted to SWCAA on Excel spreadsheets, so I have not had need to confirm that TransAlta also retained the records.

M37. 40 CFR 63 Subpart DDDDD Recordkeeping **40 CFR 63.7555**
40 CFR 63.7560

The Permittee must record and maintain the following records for the Auxiliary Boiler (EU-3): [40 CFR 63.7555]

(a) A copy of each notification and report submitted to comply with 40 CFR 63 Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or compliance report submitted according to the requirements of 40 CFR 63.10(b)(2)(xiv); [40 CFR 63.7555(a)(1)] and
(b) A copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the Auxiliary Boiler was operating. [40 CFR 63.7555(a)(3)]

The records must be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). The records must be maintained for five years following the date of each occurrence, measurement, maintenance, corrective action, report or record. Each record must be kept on site, or they must be accessible from on site, for at least two years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. The Permittee may keep the records off site for the remaining three years. [40 CFR 63.7560]

(a) TransAlta submitted an initial notification for EU-3 under the revised rules issued January 31, 2013, in a letter to EPA Region 10 and SWCAA dated May 1, 2013.
(b) The applicable permit is SWCAA Regulatory Order to Establish RACT 97-2057R1, available online.

M38. 40 CFR 60 Subpart Y Recordkeeping **40 CFR 60.258**
SWCAA 14-3093 Conditions 12 and 13

This requirement was related to the Fine Coal Recovery process. The fine coal recovery process was retired effective June 30, 2021, and all associated equipment has been removed.

G. Compliance Summary:

No potential compliance issues were identified during this inspection. However, during the semi-annual reports review I noticed that startup reports indicate that coal firing began before the wet scrubber was operational during all four startups in the first half of 2025. Effective January 2025, 40 CFR 63 Subpart UUUUU requires that "Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR." [40 CFR 63 Subpart UUUUU, Table 3, Section 3(a)(1)].

H. Appendices and Attachments:

Appendix 1 – Regulatory Summary

Appendix 1 – Regulatory Summary (Orders/Permits)

Order/Permit Number	App. #	Date Issued	Description
69-1107LET	L-1	11-7-69	Approval to construct Units #1 and #2
72-0804LET	N/A	8-4-72	Approval to restart after outage – output not to exceed 300 MW unless approved after PM compliance indicated by testing
72-0914LET	N/A	9-14-72	Approval given for operation at 400 MW
72-1006LET	N/A	10-6-72	Approval given for operation at 500 MW
72-1017LET	N/A	10-17-72	Approval to operate Unit #2 at full load for 48 hour demonstration
72-1102LET	N/A	11-2-72	Approval to operate Unit #1 at same load as Unit #2
72-1211LET2	N/A	12-11-72	Approval given for operation of each unit up to 500 MW, PM not to exceed 0.06 gr/dscf
73-0329LET	L-49	3-29-73	Approval to install SO_3 conditioning system to aid PM removal in Koppers ESPs
73-0413LET	L-50	4-13-73	Approval to install second set of ESPs as pilot test
73-0426LET	N/A	4-26-73	Regulatory Order requiring testing to provide additional information on SO_3 conditioning system
73-0504LET	N/A	5-4-73	Required testing and reporting for ESP pilot test program
73-0522LET	N/A	5-22-73	Modified dates and operating conditions specified in 4-4-73 letter
73-0611LET	N/A	6-11-73	Approval to operate Unit #1 at up to 700 MW w/ PM $\leq$ 0.06 gr/dscf
74-0207LET	L-50R	2-7-74	Approved design and installation of second set of ESPs
74-0222LET	N/A	2-22-74	Revision to clarify language in 2-7-74 letter
74-38	N/A	3-25-74	Specifies testing on Unit #2
74-38A	N/A	5-2-74	Extends high load testing days to 30
87-934	N/A	8-26-87	Order of Violation – Exceedance of 1,000 ppm SO_2 limit, inconsistent with 1969 application, penalties levied, required to sample coal, stack SO_2.
87-934-STAY	N/A	9-21-87	Order staying for 18 months requirements for SO_2 sampling, coal S sampling, and withdrawing Order of Violation 87-934 if compliance with ambient SO_X limits met despite being above 1,000 ppm limits.
88-934	N/A	2-24-88	Order, Withdrawal of Stay, and Modification of Order of Violation - Required to study lime injection, blend and wash coal install continuous SO_2 and O_2 emissions monitors, install ambient air quality monitors at three sites near the facility.

Order/Permit Number	App. #	Date Issued	Description
88-934B	N/A	7-14-98	Variance and Modification of Order – Modified SO_2 averaging period, required ambient modeling and collection of meteorological data.
88-934C	N/A	10-24-99	934C Variance Renewal and Modification of Order - extended the variance for weekly instead of hourly averaging of SO_2 emissions until November 25, 1990, extended the collection of ambient monitoring data through September 30, 1990, and modified the ambient air monitoring provision to require two rather than three sites
90-934D	N/A	11-9-90	Variance Renewal and Modification of Order - extended the variance for weekly instead of hourly averaging of SO_2 emissions until the earlier of November 25, 1991 or the date on which practicable means for the adequate abatement or control of SO_2 emissions from the Centralia Plant become known, available, and implementable. The Order required that collection of ambient meteorological monitoring data extend through September 30, 1991, and that the permittee report to SWCAA the results of its dispersion modeling by December 31, 1991.
90-934E	N/A	4-5-91	Withdrawal of Petition, Surrender of Variance, and Order - terminated the variance, meteorological monitoring, ambient monitoring, dispersion modeling, and modeling report provisions of SWCAA 90-934D and 88-934.
95-1787	N/A	8-25-95	RACT order limiting SO_2 emissions to 1.1 lb/MMBtu
96-1872	N/A	3-20-96	Withdraws RACT Order 95-1787. Replaced with a Letter of Agreement between SWCAA and PacifiCorp.
97-2057	N/A	12-8-97	Determination of SO_2, NO_X, CO and PM RACT, SO_2 and NO_X controls
97-2057R1	N/A	2-26-98	Revision of RACT determination
99-2187	N/A	2-1-99	Stay Order extending the date when procurement contract for Unit #1 control technology must be signed by 60 days (new date May 31, 1999).
01-2350	L-480	5-30-01	Minor source permit for combustion turbine project. Does not address PM or NO_X emissions
PSD-01-01	N/A	2-22-02	PSD permit for combustion turbine project – addresses PM and NO_X emissions
01-2403	L-490	2-27-02	Replacement of the Unit 1 and Unit 2 Turbine Lube Oil Mist Eliminators and Replacement of Two Rotary Fly Ash Unloaders With a Single Pug Mill

Order/Permit Number	App. #	Date Issued	Description
01-2350R1	L-496	5-6-02	Modification of 01-2350 primarily to increase SO_2 limit to account for higher sulfur content in natural gas
PSD-01-01 Amendment 1	N/A	1-30-03	Modification of PSD-01-01 to accommodate a larger than originally permitted BHP auxiliary boiler
01-2350R2	L-505	10-15-03	Modification of 01-2350R1 to accommodate a larger than originally permitted BHP auxiliary boiler.
PSD-01-01 Amendment 2	N/A	6-11-04	Modification of PSD-01-01 Amendment 1 to allow use of 40 CFR 75 RATA schedule where 40 CFR 60 schedules had been required.
01-2350R3	L-552	5-12-05	Modification of source testing and RATA frequencies for Combustion Turbine Facility
05-2612	L-556	7-15-05	Expansion of West Coal Unloading Facility with addition of 1 hopper
05-2636	L-565	11-23-05	Installation of FGD Bleed Treatment Lime Storage Silo
07-2712	L-590	2-7-07	Modification of West Coal Unloading Facility with surge capacity addition
07-2749	L-603	9-26-07	Installation of East Coal Unloading Facility and modification of requirements for West Coal Unloading Facility. After removal of the West Coal Unloading Facility in 2011, East Coal Unloading Facility simply referred to as the Coal Unloading Facility.
01-2350R4	L-608	1-18-08	Elimination of 1.5 ppmvd @ 15% O_2 (8-hour average) CO emission limit for BHP Project combustion turbines. The 3.0 ppmvd @ 15% O_2 (1-hour average) limit was retained.
08-2779	L-613	3-12-08	Replacement of the existing 1,800 cfm cartridge-style Torit baghouse with a larger Donaldson Torit cartridge style baghouse rated at 4,000 cfm in the Journal Shop.
09-2876	L-634	6-16-09	Installation and operation of a 251 horsepower nonroad engine that will drive a Jetstream pressure washer. The engine and pressure washer package will be mounted on a mobile trailer for use throughput the power plant and associated facilities. Because this is a non-road engine, it is not part of the facility's Title V permit.
Order No. 6426	N/A	6-18-10	BART Order from Washington Department of Ecology establishing NO_X emission limit of 0.24 lb/MMBtu for the coal fired boilers and coal quality requirements. EPA approved the SIP submission containing this BART submission in a Federal Register notice dated December 6, 2012.

Order/Permit Number	App. #	Date Issued	Description
11-2972	L-647	4-14-11	Installation and operation of an emergency water pump at the (East) CUF powered by a diesel engine. Superseded 07-2749.
11-2984	L-650	6-14-11	Installation of equipment associated with activated carbon injection mercury emission control system.
11-2996	L-654	11-3-11	Installation and operation of the Pump 8 Engine. This permit also addressed the grandfathered engine on Barge 5429. Note that Pump 8 was subsequently referred to as the Pump-05 engine.
First Revision of Order No. 6426	N/A	12-13-11	Revision of BART Order 6426 with new requirements for SNCR.
12-3016	L-657	4-30-12	Installation of a baghouse to replace the existing baghouse on the fly ash weigh bin (operated by Lafarge North America), and the relatively new "Fly Ash Bin 11 to Weight Hopper Air Slide Filter" (operated by TransAlta). The new baghouse filters dust from air collected from the fly ash loading spout and air vented to the fly ash bin from the #11 Air Slide and the #12 Air Slide.
12-3035	L-659	10-18-12	Installation of a new fire pump engine that may also be used to supply water to other systems at the plant during a maintenance event. Superseded 11-2996.
14-3093	L-668	4-30-14	Approval of coal mine waste reprocessing activities and fine coal recovery at TransAlta Centralia Mining and delivery by conveyor to TransAlta Centralia Generation.
16-3188	L-683	6-1-16	Approval of one trailer-mounted water pump driven by a 99 horsepower diesel engine and one Caterpillar emergency generator set powered by a 480 horsepower diesel engine to replace the Unit #2 emergency generator set.
16-3202	N/A	12-13-16	Regulatory order to limit SO_2 emissions to protect 1-hour SO_2 NAAQS.
Second Revision of Order No. 6426	N/A	7-29-20	Revision of BART Order 6426 with lower NO_X limit for one unit and removal of prescriptive SNCR operating requirements.

Bold references indicate that the order/permit was superseded or is no longer in effect.

SWCAA
Southwest Clean Air Agency

5101 NE 82nd Ave, Ste 102
Vancouver, WA 98662
(360) 574-3058
www.swcleanair.gov

December 12, 2025

Mr. Sam Bocook
TransAlta Centralia Generation, LLC
913 Big Hanaford Road
Centralia, WA 98531

Dear Mr. Bocook:

The enclosed inspection report summarizes the Southwest Clean Air Agency's (SWCAA) findings from our most recent periodic inspection of your facility. This inspection was conducted by SWCAA staff on October 23 and November 4, 2025. This document contains a summary of your facility's emission units and annual emissions, observations from SWCAA's inspection, applicable requirements/emission limits, and a compliance summary for the facility including identification of any violations that were found. It is your ongoing responsibility to maintain continuous compliance with all of the applicable air pollution control requirements for your facility as defined and referenced in SWCAA's regulations (SWCAA 400 through 493) and any SWCAA Air Discharge Permits which have been issued for your facility, as well as any state (WAC 173) and federal (40 CFR) regulations which apply.

Please review this document carefully and note that any information contained within it is considered public domain and not confidential. If you find any discrepancies or have any questions, please contact me at (360) 574-3058 extension 131.

Sincerely,

Clint Lamoreaux

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-131:
Southwest Clean Air Agency Basis Statement for TransAlta 2021 Title V Air Operating Permit

TransAlta Centralia Generation, LLC
Centralia Plant

Title V Basis Statement

September 22, 2021

Southwest Clean Air Agency
11815 NE 99th Street, Suite 1294
Vancouver, WA 98682-2322
Telephone: (360) 574-3058

PERMIT No.:	SW98-8-R5-A
PREPARED FOR:	TransAlta Centralia Generation, LLC Centralia Plant 913 Big Hanaford Road Centralia, WA 98531
PLANT SITE:	Centralia Plant 913 Big Hanaford Road Centralia, WA 98531
PERMIT ENGINEER:	Clinton H. Lamoreaux, Air Quality Engineer
REVIEWED BY:	Paul T. Mairose, Chief Engineer

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I. GENERAL INFORMATION AND CERTIFICATION

1. Company Name: TransAlta Centralia Generation, LLC

2. Facility Name: Centralia Plant

3. Contact Person: Mickey Dreher, Plant Manger

4. Inspection Contact Person: David Raastad, Manager EH&S

5. Unified Business Identification Number: 601-985-591

6. SIC Number: 4911

7. Basis for Title V Applicability:

The Centralia Steam Electric Generating Plant has the potential to emit more than 100 tons per year of sulfur dioxide, nitrogen oxides, particulate matter with an aerodynamic diameter less than 10 microns, particulate matter with an aerodynamic diameter less than 2.5 microns, and carbon monoxide which are criteria air pollutants listed under section 302 of the Federal Clean Air Act, more than 100 tons per year of volatile organic compounds (VOCs), and the potential to emit more than 25 tons per year of all hazardous air pollutant (HAP) emissions combined, which are listed under Section 112 of the Clean Air Act.

Facilitywide Potential To Emit Summary (not including nonroad engines)

Pollutant	Potential Emissions (tons per year
Nitrogen oxides	6,760
Carbon monoxide	8,044
Volatile organic compounds	87
Sulfur dioxide	5,917
Particulate Matter	1,929
PM_{10}	1,467
$PM_{2.5}$	1,386
Combined HAPs	53
Individual HAP	28 (HF)
CO_2 equivalent	8,081,792

8. Current Permitting Action:

This Title V Air Operating Permit is being re-issued to incorporate revisions to 40 CFR 63 Subpart UUUUU "National Emission Standards for Hazardous Air Pollutants: Coal and Oil-fired Electric Utility Steam Generating Units" and the latest revision to BART Order 6426. In addition, units that were removed from service with the shutdown of Unit 1 have been removed, regulatory date citations have been updated, the permit format has been modified, minor typographical errors have been corrected and the word "shall" has been removed or replaced in each instance to improve clarity.

9. Attainment Area:

The Centralia Plant is located in an area that is in attainment or unclassifiable for all criteria pollutants.

10. Facility Description:

Coal Plant

The Centralia Coal Plant generates electric energy from a steam driven turbine. Pulverized coal is combusted in a single boiler to create heat that generates pressurized steam used in the turbine. Until December 31, 2020 when "Unit 1" retired, the facility utilized two coal-fired boilers, therefore permits and historical references will frequently refer to two boilers (Unit 1 and Unit 2). Combustion of coal produces emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_X), particulate matter (PM), carbon monoxide (CO), volatile organic compounds (VOCs), and certain hazardous air pollutants (HAPs) in sufficient quantities to designate the facility as a Title V source of air pollutants.

Until May 4, 2000, PacifiCorp owned the largest share of the Centralia Plant and operated the facility on behalf of all eight utility owners. As of May 4, 2000, TransAlta Centralia Generation, LLC took over ownership of the plant. The plant consists of one 670 net MW unit identified as Unit 2 (Acid Rain Program designation BW22) which is the source of nearly all emissions released from the facility. An auxiliary boiler is used to provide steam for starting the main coal-fired boiler when it is off line. Historically, coal was supplied primarily from the adjacent TransAlta Centralia Mining, LLC (a subsidiary of TransAlta) mine and stacked and reclaimed in the Centralia Plant's coal handling yard. A smaller portion of coal from the Powder River Basin in Wyoming was blended with Centralia coal to meet Btu requirements in the boilers and, potentially, to ensure that the hourly SO_2 emission limit continued to be met. The coal mine ceased active mining operations in November 2006 and currently almost all coal is supplied from the Powder River Basin. Since 2015 a small percentage of coal is supplied coal fines recovered during the reclamation process of the fine coal refuse impoundments formed during the Centralia Mine's coal washing process. The coal mine could conceivably re-open and once again supply coal to the power plant in the future.

Particulate matter from coal combustion is controlled by dual electrostatic precipitators (ESPs) in series. Sulfur dioxide emissions are managed by coal blending and scrubbing of the flue gas. Mercury emissions are controlled by an activated carbon injection system upstream of the second set of ESPs coupled with a sorbent enhancement additive injected into the boiler. The mercury control systems were completed November 24, 2011. NO_X emissions are controlled with low-NO_X burners with coupled over-fire air systems (LNC3) and a selective non-catalytic reduction system (SNCR). The LNC3 controls were installed on Unit 2 in 2001. The SNCR systems were installed on both units in 2012. Emissions of other gaseous pollutants are minimized through good combustion practices. A portion of the fly ash captured in the ESPs is sold and shipped off site while the balance is stockpiled or trucked to the Centralia Mine landfill site. Bottom ash is also sold, stockpiled, or returned to the Centralia Mine landfill site. Additional emission points include the cooling towers, coal storage and handling yard, emergency diesel generators, mist eliminators for turbine lube oil ventilation exhaust, and maintenance activities.

The Centralia Coal Plant's two units can operate continuously 24 hours per day, 7 days per week. One or the other, and occasionally both, of the units are taken off line for maintenance purposes as conditions dictate, for economy, or reserve shut down. The auxiliary boiler operates only as needed, which is typically less than 120 hours per year.

Combustion Turbine Facility

Construction of the combustion turbine project commenced in 2001 and was completed during the summer of 2002. The project was permitted as a major modification to an existing major source. The Combustion Turbine Facility, with the exception of the Black Stop Diesel Generator Engine, was retired effective January 1, 2015. The Black Stop Diesel Generator Engine was retired at the end of 2020.

11. SWCAA Air Discharge Permits and Consent Order(s):

The following table lists each Air Discharge Permit and Consent Order(s) issued for this facility. Permits or Orders in bold contain no active requirements. The requirements may have been superseded, may have been of limited duration, or the equipment may have been removed.

Order/Permit Number	App. No.	Date Issued	Description
69-1107LET	L-1	11-7-69	Approval to construct Units 1 and 2
72-0804LET	N/A	8-4-72	Approval to restart after outage – output not to exceed 300 MW unless approved after PM compliance indicated by testing
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74-0702LET	L-50R	2-7-74	Approved design and installation of second set of ESPs

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74-0222LET	N/A	2-22-74	Revision to clarify language in 2-7-74 letter
74-38	N/A	3-25-74	Specifies testing on Unit 2
74-38A	N/A	5-2-74	Extends high load testing days to 30
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88-934B	N/A	7-14-98	Variance and Modification of Order – Modified SO_2 averaging period, required ambient modeling and collection of meteorological data.
88-934C	N/A	10-24-99	934C Variance Renewal and Modification of Order - extended the variance for weekly instead of hourly averaging of SO_2 emissions until November 25, 1990, extended the collection of ambient monitoring data through September 30, 1990, and modified the ambient air monitoring provision to require two rather than three sites
90-934D	N/A	11-9-90	Variance Renewal and Modification of Order - extended the variance for weekly instead of hourly averaging of SO_2 emissions until the earlier of November 25, 1991 or the date on which practicable means for the adequate abatement or control of SO_2 emissions from the Centralia Plant become known, available, and implementable. The Order required that collection of ambient meteorological monitoring data extend through September 30, 1991, and that the permittee report to SWCAA the results of its dispersion modeling by December 31, 1991.

Order/Permit Number	App. No.	Date Issued	Description
90-934E	N/A	4-5-91	Withdrawal of Petition, Surrender of Variance, and Order - terminated the variance, meteorological monitoring, ambient monitoring, dispersion modeling, and modeling report provisions of SWCAA 90-934D and 88-934.
95-1787	N/A	8-25-95	RACT order limiting SO_2 emissions to 1.1 lb/MMBtu
96-1872	N/A	3-20-96	Withdraws RACT Order 95-1787. Replaced with a Letter of Agreement between SWCAA and PacifiCorp.
97-2057	N/A	12-8-97	Determination of SO_2, NO_X, CO and PM RACT, SO_2 and NO_X controls
97-2057R1	N/A	2-26-98	Revision of RACT determination
99-2187	N/A	2-1-99	Stay Order extending the date when procurement contract for Unit 1 control technology must be signed by 60 days (new date May 31, 1999).
01-2350	L-480	5-30-01	Minor source permit for combustion turbine project. Does not address PM or NO_X emissions
PSD-01-01	N/A	2-22-02	PSD permit for combustion turbine project – addresses PM and NO_X emissions
01-2403	L-490	2-27-02	Replacement of the Unit 1 and Unit 2 Turbine Lube Oil Mist Eliminators and Replacement of Two Rotary Fly Ash Unloaders With a Single Pug Mill
01-2350R1	L-496	5-6-02	Modification of 01-2350 primarily to increase SO_2 limit to account for higher sulfur content in natural gas
PSD-01-01 Amendment 1	N/A	1-30-03	Modification of PSD-01-01 to accommodate a larger than originally permitted BHP auxiliary boiler
01-2350R2	L-505	10-15-03	Modification of 01-2350R1 to accommodate a larger than originally permitted BHP auxiliary boiler.
PSD-01-01 Amendment 2	N/A	6-11-04	Modification of PSD-01-01 Amendment 1 to allow use of 40 CFR 75 RATA schedule where 40 CFR 60 schedules had been required.
01-2350R3	L-552	5-12-05	Modification of source testing and RATA frequencies for Combustion Turbine Facility
05-2612	L-556	7-15-05	Expansion of West Coal Unloading Facility with addition of 1 hopper

Order/Permit Number	App. No.	Date Issued	Description
05-2636	L-565	11-23-05	Installation of FGD Bleed Treatment Lime Storage Silo
07-2712	L-590	2-7-07	Modification of West Coal Unloading Facility with surge capacity addition
07-2749	L-603	9-26-07	Installation of East Coal Unloading Facility and modification of requirements for West Coal Unloading Facility. After removal of the West Coal Unloading Facility in 2011, East Coal Unloading Facility simply referred to as the Coal Unloading Facility.
01-2350R4	L-608	1-18-08	Elimination of 1.5 ppmvd @ 15% O_2 (8-hour average) CO emission limit for BHP Project combustion turbines. The 3.0 ppmvd @ 15% O_2 (1-hour average) limit was retained.
08-2779	L-613	3-12-08	Replacement of the existing 1,800 cfm cartridge-style Torit baghouse with a larger Donaldson Torit cartridge style baghouse rated at 4,000 cfm in the Journal Shop.
09-2876	L-634	6-16-09	Installation and operation of a 251 horsepower nonroad engine that will drive a Jetstream pressure washer. The engine and pressure washer package will be mounted on a mobile trailer for use throughput the power plant and associated facilities. Because this is a non-road engine, it is not part of the facility's Title V permit.
Order No. 6426	N/A	6-18-10	BART Order from Washington Department of Ecology establishing NO_X emission limit of 0.24 lb/MMBtu for the coal fired boilers and coal quality requirements. EPA approved the SIP submission containing this BART submission in a Federal Register notice dated December 6, 2012.
11-2972	L-647	4-14-11	Installation and operation of an emergency water pump at the (East) CUF powered by a diesel engine. Superseded 07-2749.
11-2984	L-650	6-14-11	Installation of equipment associated with activated carbon injection mercury emission control system.
11-2996	L-654	11-3-11	Installation and operation of the Pump 8 Engine. This permit also addressed the grandfathered engine on Barge 5429. Note that Pump 8 was subsequently referred to as the Pump-05 engine.
First Revision of Order No. 6426	N/A	12-13-11	Revision of BART Order 6426 with new requirements for SNCR.

Order/Permit Number	App. No.	Date Issued	Description
12-3016	L-657	4-30-12	Installation of a baghouse to replace the existing baghouse on the fly ash weigh bin (operated by Lafarge North America), and the relatively new "Fly Ash Bin 11 to Weight Hopper Air Slide Filter" (operated by TransAlta). The new baghouse filters dust from air collected from the fly ash loading spout and air vented to the fly ash bin from the No. 11 Air Slide and the No. 12 Air Slide.
12-3035	L-659	10-18-12	Installation of a new fire pump engine that may also be used to supply water to other systems at the plant during a maintenance event. Superseded 11-2996.
14-3093	L-668	4-30-14	Approval of coal mine waste reprocessing activities and fine coal recovery at TransAlta Centralia Mining and delivery by conveyor to TransAlta Centralia Generation.
16-3188	L-683	6-1-16	Approval of one trailer-mounted water pump driven by a 99 horsepower diesel engine and one Caterpillar emergency generator set powered by a 480 horsepower diesel engine to replace the Unit 2 emergency generator set. Superseded 12-3035.
16-3202	N/A	12-13-16	Regulatory order to limit SO_2 emissions to protect 1-hour SO_2 NAAQS.
Second Revision of Order No. 6426	N/A	7-29-20	Revision of BART Order 6426 with lower NO_X limit for one unit and removal of prescriptive SNCR operating requirements.

II. EMISSIONS UNIT DESCRIPTIONS

Summary Table

EU No.	Generating Equipment	Emission Control
EU-1	Unit 1 Boiler (BW21) – 670 MW (net), coal fired (Retired)	N/A (Retired)
EU-2	Unit 2 Boiler (BW22) – 670 MW (net), coal fired	CO: Combustion controls NO_X: Combustion controls, SNCR VOC: Combustion controls PM: Dual ESPs, wet scrubber SO_2: Wet scrubber Hg: Sorbent enhancement additive in boiler, carbon injection between ESPs
EU-3	Auxiliary Boiler – 170 MMBtu/hr, oil-fired	Fuel consumption limit
EU-4	Material Handling (Coal Handling, Ash Handling, FGD Bleed Treatment Lime Storage Silo, Limestone Ball Mill)	Coal Handling – minimal emissions, no controls necessary except use of wet suppression at Coal Unloading Facility Ash Handling – baghouse, wet suppression, and enclosure as appropriate FGD Bleed Treatment Lime Storage Silo – Baghouse Limestone Ball Mill – Wet process, full enclosure
EU-5	Turbine Lube Oil Mist Vent 1 (Retired)	N/A (Retired)
EU-6	Turbine Lube Oil Mist Vent 2	Turbine Lube Oil Mist Eliminator 2
EU-7	Black Stop Diesel Generator Engine – 1,445 hp diesel engine (Retired)	N/A (Retired)
EU-8	Journal Shop Welding	Journal Shop Welding Filter
EU-9	Emergency Diesel Generator 1	None
EU-10	Emergency Diesel Generator 2	Ultra-low sulfur fuel, EPA Tier 3 design, operating hours limit
EU-11	Fire Pump Engine (205 hp diesel engine)	Ultra low sulfur fuel, EPA Tier 3 design, operating hours limit
EU-12	Coal Unloading Facility Emergency Diesel Sump Pump Engine (115 hp diesel engine)	Ultra low sulfur fuel, EPA Tier 2 design, operating hours limit
EU-13	SEA System 1	Cartridge-style Fabric Filter
EU-14	SEA System 2	Cartridge-style Fabric Filter
EU-15	Sorbent Silo 1	Cartridge-style Fabric Filter
EU-16	Sorbent Silo 2	Cartridge-style Fabric Filter
EU-17	Fly Ash Bin 11	Baghouse

EU No.	Generating Equipment	Emission Control
EU-18	Fly Ash Bin 12	Baghouse
EU-19	Fly Ash Bin 14	Baghouse
EU-20	Fly Ash Bin 14 Air Slide to Bin 11 Air Slide	Cartridge-style Fabric Filter
EU-21	Fly Ash Bin 14 to 6050 Air Slide	Cartridge-style Fabric Filter
EU-22	Fine Coal Handling	Wet suppression

Detailed Descriptions

EU-1 Unit 1 Boiler (Retired)

EU-1 retired at the end of 2020.

EU-2 Unit 2 Boiler

EU-2 consists of the Unit 2 boiler and its exhaust gas flow path including the 470 ft tall stacks (bypass and scrubber) through which the flue gases are discharged to the ambient air. The Unit 2 boiler is a Combustion Engineering coal-fired steam generator equipped with superheat and reheat that combusts pulverized coal in a divided furnace with tangential injection of pulverized coal and combustion air. The eight corners (four in each half of the split furnace configuration) of the boiler are supplied with fuel and air by eight levels of burners, with each level supplied by one of the eight coal pulverizers. A maximum design capacity of 490 tons per hour of coal can be combusted in the boiler. Typically, full load is attained burning 420 tons per hour of average heat content coal by operating seven of the eight pulverizers at rated capacity. Incidental quantities of on-site generated dangerous waste, used oil and grease may also be burned in the boiler. Combustion produces emissions of SO_2, NO_X, CO, PM, VOCs, and HAPs. Flue gases exit the boiler through heat exchangers and pass first through a Koppers electrostatic precipitator (ESP) with a specific collection area of 383 ft^2/1,000 acfm, and then through a Lodge-Cottrell ESP with a specific collection area of 384 ft^2/1,000 acfm for removal of particulate matter. The dual ESP system achieves a collection efficiency of 99.7% or better for particulate matter. Final flue gas treatment occurs in a forced oxidation limestone flue gas desulfurization system (wet scrubber) installed in 2001. The original stack has been retained for bypass operations during emergencies, startup, shutdown, and outages of the flue gas desulfurization system.

Mercury emissions are controlled by an activated carbon injection system upstream of the second set of ESPs coupled with a sorbent enhancement additive injected into the boiler. The mercury control system was completed November 24, 2011. NO_X emissions are controlled with "Low-NO_X Combustion, Level 3" (LNC3) controls consisting of Alstom concentric firing, low NO_X burners with close coupled and separated over-fire air. The LNC3 controls were installed in 2001.

The SNCR system was installed in 2012 and consists of Nalco Mobotec's Rotamix SNCR system. The system consists of concentrated urea storage, urea dilution, and three levels of diluted urea injection near the top of the boiler. Each urea injection point utilizes an air atomizing nozzle with annular air to allow the urea to be dispersed into the boiler before

reacting. Each nozzle can be angled approximately 30 degrees upward or downward. The lowest level of injectors is approximately at the 10.5 floor level. Each of the three horizontal levels consists of six injectors spread across the front of the boiler, with four more injectors slightly above the row of six, for a total of 30 injectors. A single air header with a blower supplies ambient air to all of the annular air supplies on the boiler. The air intake for these blowers is inside the top of the boiler building.

Each SNCR blower or pump has a redundant backup to minimize the possibility of a system outage. As the temperature regime changes with changing boiler load, the levels at which the urea is injected is modified accordingly to ensure the proper injection location.

The following individual pieces of equipment are associated with EU-2:

Equipment	Facility Designation
One Boiler for Unit 2	Unit 2 or BW22
Two ESP units in series	Koppers 21 & 22; Lodge-Cottrell 21A & 22A
Unit 2 wet scrubber	FGD 2

Construction of EU-2 officially commenced (for the purposes of 40 CFR 60) with signing of a construction contract on December 23, 1968. EU-2 commenced commercial operation in September 1972.

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart UUUUU

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	6,744	Yes/No[1]	Yes	No. Permit requires CEMS.
CO	8,042	No	Yes	No. No emission control equipment and the permit requires CEMS.
VOC	86	No	No	No
SO_2	5,913	Yes	Yes	No. Permit requires CEMS.
PM_{10}	1,277	Yes	Yes	Yes. See M20 of Permit.
NH_3	220	No	Yes	No
HF	28	Yes	No	No

[1] SNCR is available but there is no requirement to use the system and there is little likelihood the system will be used in the future.

EU-3 Auxiliary Boiler

EU-3 consists of the auxiliary boiler which is used to provide auxiliary steam throughout the plant when sufficient auxiliary steam is not available from Unit 2, such as during cold startup. The auxiliary boiler is a Babcock & Wilcox watertube steam boiler (National Board number 23173, Washington State ID number 26415-71W) with a rated capacity of 115,000 lb/hr of steam and 170 MMBtu/hr. It combusts No. 2 fuel oil, also known as distillate grade diesel fuel, to produce steam at 150 psig and 500°F and discharges flue gases through a 5 ft diameter

steel stack 250 ft in height. EU-3 emits NO_X, SO_2, CO, PM, and VOCs from combustion of No. 2 fuel oil.

Construction of EU-3 officially commenced (for the purposes of 40 CFR 60) with signing of a construction contract on December 23, 1968.

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart DDDDD

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	6.00	No	No	No
CO	1.50	No	No	No
VOC	0.08	No	No	No
SO_2	4.26	No	No	No
PM_{10}	0.99	No	No	No

EU-4 Material Handling

EU-4 consists of all coal handling equipment and operations on the Centralia Plant site, the ash collection and load-out facilities, the FGD Bleed Treatment Lime Storage Silo, and the Limestone Ball Mill. The coal handling equipment receives and stores the coal, reclaims coal from storage piles, and distributes the coal throughout the plant. Historically, coal has been received from the adjacent coal mine and delivered from the Powder River Basin. Most of the coal combusted in the Centralia Plant has been obtained from the adjacent TransAlta Centralia Mining (TCM) mine, which processed coal at its preparation plant and transferred the coal by conveyor to the Centralia Plant. This mine is currently closed. Coal is received by rail car at the Coal Unloading Facility from which it is transferred by conveyor and mobile machinery to storage piles. Note that prior to 2011 there were two Coal Unloading facilities. One located at the West end of the plant site and one located the East end of the plant site. The West Coal Unloading Facility was removed from service in 2011. Except for descriptions in historical context all coal is unloaded at a single point: the Coal Unloading Facility formerly the known as the East Coal Unloading Facility. In 2007 the permittee received an Air Discharge Permit to construct the Coal Unloading Facility. A traveling bucket-wheel stacker-reclaimer transfers yard conveyor transported coal to or from ready storage piles. In addition, a coal blending system installed in 2001 supplies coal to the plant from the ready storage pile. Dust suppression is provided to minimize generation of fugitive dust as coal is transported to the silos and pulverizers.

Fly ash is collected in storage silos and sent off-site via one of two load-out facilities. A portion of the fly ash is sold and loaded into trucks by an off-site contractor who is contractually responsible to the permittee for operation and air quality compliance of these truck-loading facilities at the Plant. Permittee is ultimately responsible for compliance under the Clean Air Act at this facility. The other load out operated by the Plant is used to dispose of fly ash in the TCM mine. Bottom ash is dewatered in settling tanks and loaded while damp into trucks for transport to the TCM mine as backfill or sold for off site use.

The following individual pieces of equipment are associated with EU-4:

Equipment	Facility Designation
Coal Unloading Facility	CUF
Twelve coal conveyors	Conveyors 1-5, 6A, 6B, 7, 11, 12, 21, & 22
One bucket-wheel stacker-reclaimer	Stacker-reclaimer
Coal blending system	
Chemical stabilizing dust suppression systems at CUF and No. 5 reclaim	(N/A)
Four coal silos	Silos 21-28 (Unit 2)
Coal surge bin	(N/A)
Four bottom ash dewatering bins	Bins 11, 12, 21, 22
Various mobile machinery	(N/A)
Four fly ash bins	Bins 11, 12, 13, 14
Fly Ash Weigh Bin Baghouse	Same
FGD Bleed Treatment Lime Storage Silo	Same
Limestone Ball Mill	Same

Bin 11 – Unclassified ash with single UCC model 6050 pin paddle mixer/unloader – 330 tph capacity, installed in 2009

Bin 12 – Classified ash with single UCC model 6050 pin paddle mixer/unloader – 330 tph capacity, installed in 2009

Bin 13 – Repurposed as a boron removal clarifier in the FGD Bleed Treatment system

Bin 14 – Replaced into service in 2011 to handle fly ash from the Lodge-Cottrell that contains carbon sorbent from the mercury control system.

Coal Unloading Facility Details

The Coal Unloading Facility consists of two below-grade hoppers, each associated with a drag flight conveyor that transfers coal to an interim conveyor that feeds the new radial stacker or feeds directly into the coal blending system. The radial stacker transfers coal to the plant stockpiles. Coal in the coal stockpiles is dozed to the coal blending/plant feed conveyors. The following transfer points are associated with the Coal Unloading Facility:

1. Rail car to below-grade hoppers (2)
2. Below-grade hoppers to apron feeders
3. Apron feeders to Conveyor 8A
4. Conveyor 8A to Conveyor 8B (stacker)
5. Conveyor 8B (stacker) to coal stockpile or Conveyor 8C
6. Conveyor 8C to ground level reclaims 3, 3A
7. Reclaims 3, 3A to Conveyor 4 or 4A (which feed the plant)

The maximum coal unloading rate is 4,000 tons per hour with 5,000 ton per hour surge capacity. The Coal Unloading Facility began operation on February 1, 2008.

FGD Bleed Treatment Lime Storage Silo Details

The FGD Bleed Treatment Lime Storage Silo stores hydrated lime ($Ca(OH)_2$). The lime is used to treat a bleed stream of scrubber liquid from the flue gas desulfurization system. The scrubber liquid treatment system is designed to reduce boron and zinc levels in the wastewater. The silo is located immediately southeast of the Unit 1 scrubber vessel. The silo is pneumatically loaded from trucks at a rate of approximately 16.7 tons per hour. Specific silo and associated dust collector information is listed below.

Silo Make/Model:	USFilter Lime Silo; WHM® Bulk Chemical Storage; Model T-1
Silo Capacity:	5,600 cubic feet
Silo Height:	53'1" without dust collector, 58' with dust collector
Dust Collector Make/Model:	C.P. Environmental Filters, Inc. / model 36-CTBFD-009-CM-30
Number of Bags:	9 cartridge style pleated "bags" measuring 6" in diameter by 36" l long
Cleaning Method:	Reverse Pulse-Jet
Cloth Area:	270 ft^2
Filter Media:	8.5 oz. pleated spun bonded polyester felt with PTFE membrane laminated to the exterior surface of the fabric
Design Exhaust Flow:	600 acfm
Installed:	2006

The manufacturer warrants that the particulate matter concentration in the effluent gas will not exceed an average of 0.005 gr/acf based on an inlet loading of 10 gr/acf.

Limestone Ball Mill Details

The Limestone Ball Mill is located in the ground floor of the FGD Building. The Limestone Ball Mill crushes limestone transferred from the limestone storage silo with water to form a limestone slurry for use in the Flue Gas Desulfurization systems. The Limestone Ball Mill is fully enclosed and is not a potential source of particulate matter emissions (the process is fully enclosed and water is injected at the upstream end of the ball mill), however it is an "affected facility" for the purposes of Title 40 Code of Federal Regulations (CFR) Part 60 Subpart OOO "Standards of Performance for Nonmetallic Mineral Processing Plants."

Ball mill processing capacity:	41 tons per hour
Manufacturer:	Svedala Industries (now known as Metso Minerals)
Serial number:	49663
Manufacture date:	May 2000
Installation date:	September 2001

Fly Ash Weigh Bin Baghouse Details

The Fly Ash Weigh Bin receives fly ash from the No. 11 Air Slide and the No. 12 Air Slide. The Fly Ash Weigh Bin was manufactured by Halliburton and has a capacity of up to 30,000 pounds. During normal operation, approximately 900 cfm of fluidizing air from one of the air slides is vented out of the Fly Ash Weigh Bin Baghouse. The Fly Ash Weigh Bin Baghouse draws approximately 900 cfm of air from the fly ash loading spout to control fugitive dust while loading, for a total air flow of 1,800 cfm. At times total airflow could range up to 2,700

cfm if fly ash were being loaded into the Fly Ash Weigh Bin from both air slides (i.e. more than one Fly Ash Bin) simultaneously. The Fly Ash Weigh Bin Baghouse is turned on/off by the contractor in charge of loading fly ash (currently Lafarge North America), however TransAlta will retain responsibility for maintenance of, and the emissions from, the Fly Ash Weigh Bin Baghouse. The following details of the cartridge collector were provided:

Baghouse Make / Model:	Donaldson Torit / Powercore CPV-4
Installed:	Installation completed July 30, 2012
Design Flow Rate:	2,700 cfm (rated at 1,400 cfm to 2,700 cfm)
Filter Description:	4 cartridges (7" wide x 22" long x 7.5" tall), total of 252 ft^2 filter area
Filter Description:	Ultra-web nanofiber material
Cleaning Method:	Pulsed jet – collected fly ash will drop down into the fly ash weigh bin.
Stack Description:	16" inside diameter stack exhausting vertically approximately 8' above the top of the fly ash weigh bin and 49-50' above ground level. An 18" diameter shroud (stack within a stack design) may be used to prevent rain intrusion into the stack.

Applicable NSPS/NESHAP/MACT: None

CAM Applicability Review

Particulate matter is the only regulated pollutant of interest for units that comprise EU-4. Equipment that utilizes a control device and has a particulate matter emission limit is reviewed below.

Equipment	Uncontrolled PTE (tons)	Subject to CAM?
FGD Bleed Treatment Lime Storage Silo	12[1]	No
Fly Ash Bin 11	0[2]	No. CAM plan is included in the Permit as M31 for the exhausts (treated as separated EUs from the piping, storage, and transfer equipment listed here).
Fly Ash Bin 12		
Fly Ash Bin 14		
Fly Ash Weigh Bin	68[3]	No

[1] Assumes an inlet loading of 10 gr/dscf (likely a gross overestimate) for a potential operating time of 467 hours per year based on 6 25-ton loads per week at an off-loading rate of 16.7 tons per hour. Note that the bin vent may be "inherent process equipment".

[2] This does not include the baghouses which are treated as separate EUs. This equipment consists only of sealed piping and transfer equipment which does not have emissions unless a pipe fails or leaks.

[3] Assumes 1,800 cfm of operation for 8,760 hours per year at an "uncontrolled" rate of 1 gr/dscf. Due to the nature of fly ash, filtration of some time is required, therefore at least some level of control is "inherent process equipment". Unit operates with 900 cfm of bin fluidizing air at all times, only exceeding this rate when actual loading is occurring and when the weigh bin is receiving ash from more than one storage bin at a time.

EU-5 Turbine Lube Oil Mist Vent 1 (Retired)

Retired at the end of 2020.

EU-6 Turbine Lube Oil Mist Vent 2

The Unit 2 turbine is equipped with an oil storage tank, lube oil reservoir, and other components of the lube oil system that supplies clean oil to the turbine-generator bearings and other equipment. The turbine lube oil mist eliminator controls oil droplet emissions from the vapor extractor, which removes moisture from the oil.

Turbine Lube Oil Mist Eliminator 2 is an Advanced Environmental Systems Air-Clear™ Mist Collection System sized to handle up to 1,000 cubic feet per minute (cfm) of oil mist at a concentration of 1,500 mg/m^3 and a temperature of 120°F. The mist eliminator utilizes 67 ft^2 (based on the inside diameter of cylindrical filters) of fiberbed diffusion coalescing filters to collect up to 99.5% of the liquid mists on a particle count basis. Manufacturer literature suggests that the collection efficiency can be as high as 99.99% on a mass basis. This unit is designed to maintain the exit opacity at 5% or below. The blower system is designed to supply an average exhaust flowrate of 5 cfm (maximum of 600 cfm for short periods). This is substantially lower than the 1,000 cfm design of the mist eliminator. The mist eliminator is designed so that the filter elements are replaced when the gas flow becomes overly restricted due to high differential pressure across the filters. The differential pressure across the filters is less important to emission control than the average flow velocity through the filters. The manufacturer estimates that a velocity of 40 feet per minute or less is required for adequate opacity control. The permittee's blower has the capacity to produce a velocity of approximately 9 feet per minute (600 cfm/67 ft^2).

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
VOC	0.01	Yes	Yes	No

EU-7 Black Stop Diesel Generator Engine (Retired)

The Black Stop Diesel Generator Engine retired at the end of 2020.

EU-8 Journal Shop Welding

Coal journals used in the coal pulverizers are repaired in the Journal Shop. Repairs consist primarily of welding replacement metal onto the journals to replace metal worn off during normal use. TransAlta submitted Air Discharge Permit Application L-613 on February 4, 2008 for replacement of the existing 1,800 cfm cartridge-style Torit baghouse with a larger Donald Torit cartridge style baghouse rated at 4,000 cfm. The purpose of the replacement

was to improve worker hygiene in the Journal Shop, especially to reduce potential worker exposure to chromium welding fumes.

Journal Shop – Baghouse. Journal Shop welding electrode use is less than 12,000 pounds per year. The baghouse pickups are positioned in such a way to minimize exposure of welders to welding fumes. Most welding is expected to be shielded metal arc welding. The following baghouse details were available:

Make / Model:	Donaldson Torit / DFO 2-8
Filter Area:	1,520 square feet of cartridge style filters
Primary Filter Media:	Ultra-Web FR with a MERV rating of 13
No. of Filters:	8
Secondary Filters:	Contains two 24" x 24" x 12" HEPA filters downstream of cartridge filters
Design Capacity:	4,000 cubic feet per minute @ 10" w.c., 70 °F
Installed:	September 10, 2008
Stack Description:	Exhausts horizontally through two 24" x 24" x 12" ducts at ambient temperature ~12' above grade.

Applicable NSPS/NESHAP/MACT: None

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	0.49	Yes	Yes – opacity as a surrogate for PM	No

EU-9 Emergency Diesel Generator 1

Engine Rating:	440 horsepower
Engine Make / Model:	Caterpillar / D343
Engine Serial Number:	6287637
Stack Description:	~ 8" diameter exhausted above the 8th floor roof

Diesel fuel oil is burned by this generator to supply back-up power to critical electrical systems in Unit 1. The generator is operated for about ¼ hour each week for testing, and consumes less than 300 gallons of fuel annually producing emissions below the thresholds of WAC 173-401-530(4) for an insignificant emission unit. This unit is not an insignificant emission unit because it is subject to applicable requirements found in 40 CFR 63 Subpart ZZZZ. The applicable requirements became effective May 3, 2010 (Federal Register notice dated March 3, 2010) with a compliance date of May 3, 2013.

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart ZZZZ

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	1.36	No	No	No
CO	0.29	No	No	No
VOC	0.11	No	No	No
SO_2	0.00048	No	No	No
PM_{10}	0.01	No	No	No

EU-10 Emergency Diesel Generator 2

Generator Set Make / Model:	Caterpillar / C9
Generator Output:	300 kW
Engine Make / Model:	Caterpillar / C9
Engine Serial Number:	CASP01214
Fuel:	Diesel, 22.7 gallons per hour at full load
Engine Power:	480 hp
Engine Built:	2016
Engine Certification:	EPA Tier 3 Emergency
Stack Description:	~ 7" diameter, exhausting vertically, ~8' above the 8th floor roof, stack flow 2,460.9 acfm at 927.2°F
Location:	46°45'19.19"N, 122°51'36.24"W
NSPS/NESHAP/MACT:	40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ

Applicable NSPS/NESHAP/MACT: 40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	0.42	No	No	No
CO	0.02	No	No	No
VOC	0.01	No	No	No
SO_2	0.00049	No	No	No
PM_{10}	0.0024	No	No	No

EU-11 Fire Pump Engine

The Fire Pump Engine drives a backup fire water pump. This unit will operate for testing and maintenance of the engine, as necessary during an emergency, and for limited time periods for non-emergency operation (e.g. during maintenance events when the electrical pump system is unavailable). Total annual operation is expected to be no more than 504 hours per year (3 weeks). Engine details are provided below:

Engine Make / Model:	Cummins / CFP7E-F50 Fire Pump Driver
Engine Serial Number:	73467344
Fuel:	Diesel, 10.6 gallons per hour at full load

Engine Power:	205 hp
Engine Built:	2012
Engine Installed:	Installation completed December 27, 2012
Engine Certification:	EPA Tier 3
Stack Description:	~ 4" diameter, exhausting vertically ~18' above grade, 1' 10" above roof level, stack flow 1,174 acfm @ 879°F
Location:	46°45'22.44"N, 122°51'44.23"W

Applicable NSPS/NESHAP/MACT: 40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	0.28	No	Yes	No
CO	0.14	No	Yes	No
VOC	0.01	No	No	No
SO_2	0.0006	No	No	No
PM_{10}	0.013	No	Yes	No

EU-12 Coal Unloading Facility Emergency Diesel Sump Pump Engine

The CUF Emergency Diesel Sump Pump consists of a Godwin water pump driven by a diesel engine. The engine is operated for testing, maintenance, and as an emergency backup to the existing electric water pump. Engine details are provided below:

Engine Make / Model:	John Deere / 4045TF275
Engine Serial Number:	PE 4045TF593425
Engine Family:	6JDXL06.8082
Fuel:	Diesel, 42.7 pounds per hour @ full load
Horsepower Rating:	115
Engine Built:	July 9, 2006
Engine Certification:	EPA Tier 2
Stack Description:	~ 4" diameter, exhausting vertically ~6.5' above grade, stack flow 713 acfm @ 860 °F

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart ZZZZ, 40 CFR 60 Subpart IIII

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	0.25	No	Yes	No
CO	0.04	No	Yes	No
VOC	0.0077	No	No	No
SO_2	0.00013	No	No	No
PM_{10}	0.0055	No	Yes	No

EU-13 SEA System 1

Based on a review of the potential Sorbent Enhancement Additive (SEA) materials, no significant increase in pollutant emission rates is expected as a result of injecting SEA into the boiler. Emissions are associated with venting of SEA laden air from the SEA hopper and the hammermill crusher through the SEA System 1 Cartridge Collector. The system feed capacity is 5-100 lb/hr, therefore the hammermill crusher is not subject to 40 CFR 60 Subpart OOO. The following details of the cartridge collector were provided:

Make / Model:	Grünergy Technologies / PV-2-160 AR III
Design Flow Rate:	1,130 cfm
Design Exhaust Concentration:	0.005 gr/dscf
No. of Cartridges:	2
Filter Description:	160 ft^2 of 8 oz/yd^2 thermally fused polyester with PTFE membrane
Cleaning Method:	Pulsed jet
Stack Description:	6" diameter stack exhausting vertically on east wall of the boiler building.

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	42.42[1]	Yes	Yes	No

[1] Assumes conservative (high) inlet concentration loading of 1.0 gr/dscf.

EU-14 SEA System 2

Based on a review of the potential SEA materials, no significant increase in pollutant emission rates is expected as a result of injecting SEA into the boiler. Emissions are associated with venting of SEA laden air from the SEA hopper and the hammermill crusher through the SEA System 2 Cartridge Collector. The system feed capacity is 5-100 lb/hr, therefore the hammermill crusher is not subject to 40 CFR 60 Subpart OOO. The following details of the cartridge collector were provided:

Make / Model:	Grünergy Technologies / PV-2-160 AR III
Design Flow Rate:	1,130 cfm
Design Exhaust Concentration:	0.005 gr/dscf
No. of Cartridges:	2
	Filter Description: 160 ft^2 of 8 oz/yd^2 thermally fused polyester with PTFE membrane
Cleaning Method:	Pulsed jet
Stack Description:	6" diameter stack exhausting vertically on east wall of the boiler building.

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	42.42[1]	Yes	Yes	No

[1] Assumes conservative (high) inlet concentration loading of 1.0 gr/dscf.

EU-15 Sorbent Silo 1

Sorbent Silo 1 is located directly north of the ductwork between the Koppers ESPs and the Lodge-Cottrell ESPs. The following details of the vent filter system were provided:

Make / Model:	Torit Technologies / TBV-4 Insertable
Design Flow Rate:	350 cfm, passively vented
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	4 Ultra-Web II NL cartridges, each containing a filter area of 170 ft^2 of 8 oz/yd^2 nanofiber on cellulose material
Cleaning Method:	Reverse air jet
Stack Description:	Circular exhaust measuring approximately 12" diameter exhausting vertically on the top of the silo, approximately 95' above grade

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	13.14[1]	Yes	Yes	No

[1] Assumes conservative (high) inlet concentration loading of 1.0 gr/dscf.

EU-16 Sorbent Silo 2

Sorbent Silo 2 is located directly south of the ductwork between the Koppers ESPs and the Lodge-Cottrell ESPs. The following equipment details were provided:

Make / Model:	Torit Technologies / TBV-4 Insertable
Design Flow Rate:	350 cfm, passively vented
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	4 Ultra-Web II NL cartridges, each containing a filter area of 170 ft^2 of 8 oz/yd^2 nanofiber on cellulose material
Cleaning Method:	Reverse air jet
Stack Description:	Circular exhaust measuring approximately 12" diameter exhausting vertically on the top of the silo, approximately 95' above grade

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	13.14[1]	Yes	Yes	No

[1] Assumes conservative (high) inlet concentration loading of 1.0 gr/dscf.

EU-17 Fly Ash Bin 11 Baghouse

The Fly Ash Bin 11 Baghouse is located on top of the fly ash bins. A baghouse leak detector has been installed. The following equipment details were provided:

Make / Model:	Industrial Accessories Company (IAC) / 144TB-BVWT-256-S6
Design Flow Rate:	14,730 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	256 bags, 114 inches long with a total filter area of 4,997 ft^2, top load, DuPont Type 54 or equal, polyester material.
Cleaning Method:	Reverse air jet
Stack Description:	Rectangular exhaust measuring approximately 18" x 50" exhausting vertically ~ 5' above the top of the baghouse, approximately 30' above the top of the fly ash bin.
Leak Detector:	Tribo-Flow model 4001-1111-01-154N with 12" long probe

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	553[1]	Yes	Yes	Yes – CAM plan is included in the Permit as M31.

[1] Assumes inlet concentration loading of 1.0 gr/dscf.

EU-18 Fly Ash Bin 12 Baghouse

The Fly Ash Bin 12 Baghouse is located on top of the fly ash bins. A baghouse leak detector has been installed. The following equipment details were provided:

Make / Model:	Industrial Accessories Company (IAC) / 144TB-BVWT-256-S6
Design Flow Rate:	14,730 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	256 bags, 114 inches long with a total filter area of 4,997 ft^2, top load, DuPont Type 54 or equal, polyester material.
Cleaning Method:	Reverse air jet

Stack Description: Rectangular exhaust measuring approximately 18" x 50" exhausting vertically ~ 5' above the top of the baghouse, approximately 30' above the top of the fly ash bin.

Leak Detector: Tribo-Flow model 4001-111-I-154N with 12" long probe

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	553[1]	Yes	Yes	Yes – CAM plan is included in the Permit as M31.

EU-19 Fly Ash Bin 14 Baghouse

The Fly Ash Bin 14 Baghouse is located on top of the fly ash bins. A baghouse leak detector has been installed. The following equipment details were provided:

Make / Model: Industrial Accessories Company (IAC) / 144TB-BVWT-256-S6

Design Flow Rate: 14,730 cfm

Design Exhaust Concentration: 0.005 gr/dscf

Filter Description: 256 bags, 114 inches long with a total filter area of 4,997 ft^2, top load, DuPont Type 54 or equal, polyester material.

Cleaning Method: Reverse air jet

Stack Description: Rectangular exhaust measuring approximately 18" x 50" exhausting vertically ~ 5' above the top of the baghouse, approximately 30' above the top of the fly ash bin.

Leak Detector: Tribo-Flow model 4001-111-I-154N with 12" long probe

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	553[1]	Yes	Yes	Yes – CAM plan is included in the Permit as M31.

EU-20 Fly Ash Bin 14 Air Slide to Bin 11 Air Slide

The air slide utilizes approximately 900 cfm of air to help move fly ash from Fly Ash Bin 14 to the Bin 11 Air Slide which in turn moves fly ash to the weigh hopper. The air is exhausted through a cartridge-style air filter system. The blower is located downstream of the air filter. The following equipment details were provided:

Make / Model: DCL / VML185

Design Flow Rate:	900 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	4 polyester cartridges, each measuring approximately 8" outside diameter by 22 inches long, combined filter area of 185 ft^2
Cleaning Method:	Reverse air jet
Stack Description:	Exhausts approximately 35 feet above ground on the south side of the Bin 11 building – discharged vertically through ~ 6" diameter exhaust.

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	33.8	Yes	Yes	No

EU-21 Fly Ash Bin 14 to 6050 Air Slide

The air slide utilizes approximately 600 cfm of air to help move fly ash from Fly Ash Bin 14 to the 6050 unloader. The air is exhausted through a cartridge-style air filter system. The blower is located downstream of the air filter. The following equipment details were provided:

Make / Model:	DCL / VML140
Design Flow Rate:	600 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	3 polyester cartridges, each measuring approximately 8" outside diameter by 22 inches long, combined filter area of 140 ft^2
Cleaning Method:	Reverse air jet
Stack Description:	Exhausts approximately 35 feet above ground inbetween the Bin 11 and Bin 14 buildings discharged vertically through ~ 6" diameter exhaust.

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	33.8	Yes	Yes	No

EU-22 Fine Coal Handling

Coal mine waste reprocessing and fine coal recovery activities at the Centralia Mine were approved in April 2014 and production began in December 2014. The activities involve dredging waste coal fines from ponds, processing those materials to separate fine coal from waste material, transferring waste slurry to a pit in the North Hanaford area, and transferring fine coal to the coal stockpile at TransAlta Generation. Fugitive dust may be generated at unenclosed material transfer points.

The fine coal handling equipment spans both the TransAlta Centralia Generation and TransAlta Centralia Mining facilities. Each facility maintains separate Air Operating Permits. TransAlta has indicated that after construction is complete, all equipment from Transfer Point 04 (TP-04) and downstream (including the fine coal stockpile) are the responsibility of TransAlta Centralia Generation. An enclosed conveyor will transfer fine coal over Big Hanaford Road from TransAlta Centralia Mining to TransAlta Centralia Generation. TP-04 is the first transfer point north of Big Hanaford Road. Responsibility for the equipment upstream of TP-04 has been retained by TransAlta Centralia Mining.

Transfer Point (TP)	**Emission Control Notes**
TP-01 (screen bowl centrifuge to clean coal collection conveyor)	Fully enclosed and in the process building
TP-02 (clean coal collection conveyor to 48" conveyor)	Fully enclosed
TP-03 (48" conveyor to conveyor over Big Hanaford Road)	Fully enclosed
TP-04 (transfer either to existing conveyor to directly feed power plant or transfer to fixed stacker for periods when the power plant is not running. A flop gate will direct the flow.)	Fully enclosed
TP-05 (discharge from the stacking conveyor to clean coal stockpile – estimated to be 15% of total throughput)	High pressure suppression as necessary at stacker discharge.

Conveyor Descriptions

Conveyor from TP-01 to TP-02 (Clean Coal Collection Conveyor): This 24" conveyor passes through the process building wall and is covered, but not fully enclosed, where it exits the building.

Conveyor from TP-02 to TP-03: 48" conveyor running along the south side of Parking Lot No. 2. This conveyor is covered but not fully enclosed.

Conveyor from TP-03 to TP-04 (conveyor over Big Hanaford Road): This conveyor is fully enclosed with the exception of some portal sized openings and open sides for a short distance near the head and tail pulleys.

Conveyor from TP-04 to Power Plant: This is an existing conveyor that runs along the south side of the coal plant stockpile and feeds the power plant.

Conveyor to TP-04 to Stockpile: This is an existing stacker that has been re-located to this fixed location. This is a 250' long open conveyor.

Applicable NSPS: 40 CFR 60 Subpart Y "Standards of Performance for Coal Preparation and Processing Plants."

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	0.09	Yes (water spray)	Yes	No

III. EXPLANATION OF INSIGNIFICANT EMISSIONS UNIT DETERMINATIONS

Each emission unit listed as insignificant in the permit has been reviewed by SWCAA to confirm its status. The numbering system used to identify these emission units is consistent with internal Centralia Plant designations and does not necessarily use consecutive numbers. Emission units were determined to be insignificant as follows:

IEU-55B Maintenance Shops Welding Emissions

Maintenance welding is exempt from registration according to SWCAA 400-101(10) and did not require an approval. Emissions from this discharge point are less than 0.1 ton/yr, well below the 0.75 ton PM_{10}/yr threshold of WAC 173-401-530(4)(e) so this unit is considered insignificant. Based on a conservative estimate that no more than 2,000 lb of electrode is used annually in any one shop and the highest value emission factor of 82 lb/1,000 lb from EPA AP-42 Table 12.19-1, the annual emissions are calculated to be:

2,000 lb * (82 lb/1,000 lb) * (1 ton/2,000 lb) < 0.1 ton/yr

IEU-57 Cooling Towers

Primary cooling of the process steam takes place at the cooling towers for the Coal Plant. The cooling towers are categorically exempt insignificant emissions units under WAC 173-401-532(121) because of processing exclusively non-contact cooling water. Furthermore, the cooling towers do not use chromium-based water treatment chemicals. Sodium hypochlorite is used to treat circulating cooling water and does not escape to the ambient air.

IEU-61 Cold Solvent Parts Washers

Eight parts washing solvent tanks are used at the Centralia Plant site for only non-chlorinated solvent, each tank ranging in size from 30 to 40 gallons. The tanks are covered by lids when parts are not actively loaded or unloaded into or out of the tanks. The parts washers emit minimal VOC emissions and are considered insignificant because only fugitive emissions are released consistent with the definition of insignificant emission units in WAC 173-401-530(1)(d) and because their emissions are below the 2.0 tons per year VOC threshold of WAC 173-401-530(4)(d). Based on solvent use of 12,000 lb/yr and a recycle rate of 92% estimated by the solvent recycle vendor, VOC emissions are calculated to be:

12,000 lb/yr * (1 - 0.92) * (1 ton/2,000 lb) = 0.48 tons per year VOC

IEU-71 Fuel Oil Storage Tank 1

This storage tank supplies fuel oil to the boiler for startups and has a capacity of 100,000 gallons. Its VOC emissions are well below the insignificant emission thresholds of WAC 173-401-530(4)(d) (2.0 tons per year of VOC) so the emission unit is considered insignificant. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.079 lb/1,000 gal was derived for this tank. For annual throughput of 220,000 gallons, VOC emissions are calculated to be:

220,000 gal * 0.079 lb/1,000 gal * (1 ton/2,000 lb) = 0.009 tons per year VOC

IEU-72 Fuel Oil Storage Tank 2

This storage tank supplies fuel oil to the boiler for startups and has a capacity of 100,000 gallons. Its VOC emissions are well below the insignificant emission thresholds of WAC 173-401-530(4)(d) (2.0 tons per year of VOC) so the emission unit is considered insignificant. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.079 lb/1,000 gal was derived for this tank. For an annual throughput of 220,000 gallons, VOC emissions are calculated to be:

220,000 gal * 0.079 lb/1,000 gal * (1 ton/2,000 lb) = 0.009 tons per year VOC

IEU-73 Gasoline Storage Tank

The tank is a 5,200 gallon above ground tank with a white concrete shell used to fuel vehicles and equipment on site. The tank utilizes submerged fill and is not equipped with Stage I or II vapor recovery. No pressure/vacuum valve is utilized. Annual emissions from the storage tank are reported by the permittee to be less than 0.5 ton/yr, well below the 2.0 tons VOC/yr insignificant emission threshold of WAC 173-401-530(4)(d).

Gasoline vapors are emitted primarily from the following:

1. Storage Tank Loading Losses
2. Storage Tank Breathing Losses

Storage tank loading and breathing losses were estimated using EPA's Tanks 4.09D emission estimation software.

<u>The parameters were used in Tanks 4.09D:</u>

Nearest City:	Olympia, WA
Type of Tank:	Horizontal Tank
Shell Length:	12.5'
Shell Diameter:	9'
Tank Volume:	5,200 gallons
Shell Color:	White
Shell Condition:	Poor
Vacuum Setting:	0.0 psi
Pressure Setting:	0.0 psi
Liquid:	Gasoline (RVP=10)

Based on EPA Speciate 3.2 profile number 2455, approximately 50.85% of the total VOC emissions are toxic air pollutants (TAPs) as defined by WAC 173-460, and approximately 12.91% of the total VOC emissions are federally listed hazardous air pollutants (HAPs). For a throughput of 930,000 gallons per year, TAP and HAP emission rates are estimated to be:

IEU-73 Gasoline Storage Tank Emissions

Throughput =	15,000 gallons per year
Control Efficiency =	0% (Assume no vapor balance fittings)
Emission Factors	
Storage Tank Working Losses =	7.099 lb/1,000 gallons
Storage Tank Breathing Losses =	770 lbs/year

Emissions Summary	lbs	tons
Volatile Organic Compounds	876	0.44
Toxic Air Pollutants	446	0.22
Hazardous Air Pollutants	113	0.06

IEU-74 Diesel Storage Tank

The storage tank has a capacity of 5,200 gallons and is used to fuel vehicles and equipment on site. VOC storage tanks not greater than 10,000 gallons capacity with appropriate closure and vapor pressure not greater than 80 mmHg are defined in WAC 173-401-533(2)(c) to be insignificant emission units. Annual emissions from the storage tank are reported by the permittee to be less than 0.001 ton/yr, below the 2.0 tons VOC/yr insignificant emission threshold of WAC 173-401-530(4)(d). Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.020 lb/1000 gal was derived for this tank. For an annual throughput of 16,000 gallons, VOC emissions are calculated to be:

16,000 gal * 0.020 lb/1000 gal * (1 ton/2,000 lb) = 0.0002 tons per year VOC

IEU-75 U1 Emergency Diesel Generator Fuel Storage Tank

This fuel storage tank has a capacity of 350 gallons and supplies the U1 emergency diesel generator. Storage tanks not greater than 1,100 gallons capacity with maximum vapor pressure of 550 mmHg are defined in WAC 173-401-533(2)(b) to be insignificant emission units. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.034 lb/1,000 gal was derived for this tank. For an annual throughput of 300 gallons, VOC emissions are calculated to be:

300 gal * 0.034 lb/1,000 gal * (1 ton/2,000 lb) = 0.00001 tons per year VOC

IEU-76 U2 Emergency Diesel Generator Fuel Storage Tank

This fuel storage tank has a capacity of 350 gallons and supplies the U2 emergency diesel generator. Storage tanks not greater than 1,100 gallons capacity with maximum vapor pressure of 550 mmHg are defined in WAC 173-401-533(2)(b) to be insignificant emission units. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an

effective emission factor of 0.034 lb/1,000 gal was derived for this tank. For annual throughput of 300 gallons, VOC emissions are calculated to be:

300 gal * 0.034 lb/1,000 gal * (1 ton/2,000 lb) = 0.00001 tons per year VOC

IEU-77 Emergency Diesel Fire Pump Fuel Storage Tank

This fuel storage tank has a capacity of 350 gallons and supplies the emergency diesel fire pump. Storage tanks not greater than 1,100 gallons capacity with maximum vapor pressure of 550 mmHg are defined in WAC 173-401-533(2)(b) to be insignificant emission units. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.47 lb/1,000 gal was derived for this tank. For an annual throughput of 150 gallons, VOC emissions are calculated to be:

150 gal * 0.47 lb/1,000 gal * (1 ton/2,000 lb) = 0.00004 tons per year VOC

IEU-78 Limestone Silo

The limestone silo receives limestone shipments from trucks and feeds the ball mill for the FGD system. Particulate matter emissions are controlled by a Flex-Kleen model 30/36-PVBL-9-11 G vent filter (serial number 100770) located on top of the limestone silo. The vent filter has a rated efficiency of 99.9%. The conveyor to the silo has a capacity of 200 tons per hour and the ball mill has a capacity of 41 tons per hour, therefore the unit can operate up to 8,760*(41/200) = 1,796 hours per year. The vent filter fan is rated at 900 cfm. At a maximum emission concentration of 0.005 gr/dscf (typical maximum for material handling silo filters), potential emissions are:

$$\frac{1{,}796 \text{ hours per year}}{\text{year}} * \frac{900 \text{ cubic feet}}{\text{minute}} * \frac{60 \text{ minutes}}{\text{hour}} * \frac{0.005 \text{ grains}}{\text{standard cu ft}} * \frac{1 \text{ pound}}{7{,}000 \text{ grains}} = \frac{69 \text{ pounds}}{\text{year}}$$

Emissions from this discharge point are well below the 0.75 ton PM_{10}/yr threshold of WAC 173-401-530(4)(e) so this unit is considered insignificant.

IEU-79 Lime Silo

The lime silo receives lime shipments from trucks and feeds the FGD system when necessary (e.g. ball mill is inoperable). Particulate matter emissions are controlled by a Flex-Kleen model 30-PVBL-9-11 G vent filter located on top of the limestone silo. The vent filter has a rated efficiency of 99.9%. This unit can receive approximately 25 tons per hour of material from a truck (1 truckload per hour). The vent filter fan is rated at 900 cfm. At a maximum emission concentration of 0.005 gr/dscf (typical maximum for material handling silo filters), potential emissions are:

$$\frac{8{,}760 \text{ hours per year}}{\text{year}} * \frac{900 \text{ cubic feet}}{\text{minute}} * \frac{60 \text{ minutes}}{\text{hour}} * \frac{0.005 \text{ grains}}{\text{standard cu ft}} * \frac{1 \text{ pound}}{7{,}000 \text{ grains}} = \frac{338 \text{ pounds}}{\text{year}}$$

This unit typically operates one hour per day, so typical emissions are far less than 338 pounds per year. Emissions from this discharge point are well below the 0.75 ton PM_{10}/yr threshold of WAC 173-401-530(4)(e) so this unit is considered insignificant.

IV. EXPLANATION OF SELECTED PERMIT PROVISIONS AND GENERAL TERMS AND CONDITIONS

P11. Unavoidable Excess Emissions

[SWCAA 400-107]

SWCAA 400-107 establishes criteria and procedures for determining when excess emissions are considered unavoidable. Emissions that meet the requirements to be classified as unavoidable are still considered excess emissions and are reportable but are excused and not subject to penalty. Notification of excess emissions is required as soon as possible and must occur by the next business day following the excess emissions event. Excess emissions due to startup or shutdown conditions are considered unavoidable if the permittee adequately demonstrates the excess emissions could not have been prevented through careful planning and design. Upset excess emissions are considered unavoidable if the permittee adequately demonstrates the upset event was not caused by poor or inadequate design, operation, maintenance, or other reasonably preventable condition, and the permittee takes appropriate corrective action that minimizes emissions during the event, taking into account the total emissions impact of that corrective action. Additional descriptions of potential excess emissions and how the permittee is expected to respond to those events are provided in requirements M9 and M15 - Startup, Shut Down, and Outage Operation Procedures.

The Utility MACT (Subpart UUUUU) and the Boiler MACT (Subpart DDDDD) are federally standards that can be delegated to state and local agencies and contain specific, and more restrictive, affirmative defense provisions that apply only to malfunctions. For these reasons, SWCAA has concluded that the state and local excess emission provisions cannot apply to these standards.

G2. Chemical Accident Prevention

[40 CFR 68]

Part 68 requires risk management plans be developed for the substances and thresholds listed in 40 CFR 68.130. Chlorine and ammonia are listed substances. The permittee no longer uses chlorine or ammonia on site. The SNCR system utilizes urea rather than ammonia. The permittee uses no other substance listed in 40 CFR 68.130, therefore this standard currently does not apply to this facility.

G11. Portable Sources

[SWCAA 400-036, SWCAA 400-110(6)]

SWCAA 400-110(6) establishes procedures for approving the operation of portable sources of air emissions that locate temporarily at project sites. These requirements are general statewide standards and apply to all portable sources of air contaminants. Common equipment subject to these conditions include emergency generators, engine-powered pumps, rock crushers, concrete batch plants, and hot mix asphalt plants that operate for a short time period at a site to fulfill the needs of a specific contract. Portable sources exempt from registration under SWCAA 400-101 are exempt from SWCAA 400-110 and not subject to

the portable source requirements. Among those categories listed in SWCAA 400-101 that are exempt are operations with potential to emit less than 1 ton per year of all criteria pollutants other than $PM_{2.5}$, and less than 0.5 tons per year of $PM_{2.5}$.

V. EXPLANATION OF OPERATING TERMS AND CONDITIONS

Req. 1-8 General Standards for Maximum Emissions
[SWCAA 400-040, SWCAA 01-2350R4]

SWCAA 400-040 establishes maximum emission standards for various air contaminants. These requirements are general statewide standards and apply to all sources of air contaminants. Therefore, these requirements apply to all emission units at the source, both EU and IEU. Pursuant to WAC 401-530(2)(c), the permit does not contain any testing, monitoring, recordkeeping, or reporting requirements for IEUs except those specifically identified by the underlying requirements. The averaging time for the SO_2 standard of Req-6 is satisfied by 60-minute average values averaged over each clock hour consistent with the monitoring provisions of M8.

No specific monitoring was specified for Req-7 because there are no specific monitoring requirements that can be used to encompass the whole range of potential concealment and masking scenarios. The permittee is required to certify compliance with all terms and conditions of the permit, including these prohibited items, at least annually. The permittee must make a reasonable inquiry to determine if concealment or masking has occurred during the reporting period in order to certify compliance.

Req. 9, 10 Emission Standards for Combustion and Incineration Units
[SWCAA 400-050]

SWCAA 400-050 establishes maximum emission standards for selected emissions from combustion and incineration units. These requirements apply to all combustion and incineration units at the source, both EUs and IEUs. Pursuant to WAC 401-530(2)(c), the permit does not contain any testing, monitoring, recordkeeping, or reporting requirements for IEUs except those specifically identified by the requirements as applying to IEUs.

Req. 11 Emission Standards for General Process Units
[SWCAA 400-060]

SWCAA 400-060 establishes maximum particulate matter emission standards for general process units. These requirements apply to all general process units at the source, both EUs and IEUs. Pursuant to WAC 401-530(2)(c), the permit does not contain any testing, monitoring, recordkeeping, or reporting requirements for IEUs except those specifically identified by the requirements as applying to IEUs.

Req. 12 Emission Standards for Certain Source Categories - Abrasive Blasting
[SWCAA 400-070(8)]

SWCAA 400-070 establishes emission standards for seven specific source categories. The requirements of SWCAA 400-070(8) apply due to the potential for infrequent abrasive blasting operations at the plant site. Abrasive blasting is required to be conducted inside a booth or structure designed to capture the blast grit, overspray, and removed material, except for blasting of outdoor structures and items too large to be handled inside an enclosure. Outdoor blasting is to be performed with either steel shot or an abrasive material containing less than 1 percent by mass material that would pass through a No. 200 sieve. Precautions to minimize emissions, such as enclosure of the area being blasted with tarps, are to be used for outdoor blasting.

No specific monitoring was specified for this requirement because there are no specific monitoring requirements that can be used to encompass the whole range of potential blasting scenarios. The permittee is required to certify compliance with all terms and conditions of the permit, including this requirement, at least annually. The permittee must make a reasonable inquiry to determine if prohibited activities have occurred during the reporting period in order to certify compliance.

Req. 13 Opacity Monitoring, and Reporting
[SWCAA 400-105(4)(a)(i) & (4)(e)]

SWCAA 400-105(5)(a) & (5)(e) requires that fossil fuel-fired steam generators of 250 million Btu/hr or greater heat input without sulfur dioxide control equipment install a continuous monitor for opacity, and operate it in accordance with the requirements found in 40 CFR 51, Appendix P and 40 CFR 60, Appendices B - F, as appropriate. This requirement applies to emission units EU-1 and EU-2 only during a scheduled outage of the flue gas desulfurization system and anticipated startups. Anticipated startups exclude startups immediately (less than 12 hours) following a forced outage. This requirement does not establish a visible emission standard with a specified opacity value; Reqs-1 and 15 are the applicable requirements that set a visible emission standard expressed as an opacity value to be achieved. The evaluation method is presented in Appendix A of the Air Operating Permit.

Req. 6, 14, 15, 17 - 20, 23, 24, 27, 35, 39, 40 Regulatory Order to Establish RACT
[SWCAA 97-2057R1]

The Regulatory Order to Establish Reasonably Available Control Technology (RACT) superseded all previous Orders applicable to EU-1 and EU-2.

Following extensive analysis of what constitutes RACT for this source, SWCAA issued Regulatory Order to Establish RACT SWCAA 97-2057 to the Centralia Plant on December 8, 1997 to establish Reasonably Available Control Technology (RACT) emission limits for SO_2, NO_X, PM, and CO emissions from the plant. The Centralia Plant petitioned SWCAA for a modification of the NO_X emission limit, and SWCAA revised the RACT Order as SWCAA 97-2057R1 on February 26, 1998. This Order establishes RACT emission limits for SO_2, NO_X, PM, and CO emissions, restricts the annual consumption of fuel oil by the

auxiliary boiler (EU-3), and supersedes all Orders previously issued to the Centralia Plant (see VI. Explanation of Obsolete and Future Requirements).

Section 36 of SWCAA 97-2057R1 (Requirement 15) establishes opacity limitations for the boiler (EU-2). The permittee operates opacity monitors in the ductwork upstream of the bypass stack. No correlation has been developed to describe the relationship between the opacity indicated by these monitors and the opacity of the FGD exhaust; therefore these monitors cannot be used to determine compliance with this requirement for the FGD exhaust.

Requirement 18 applies during normal operation. Emissions during startups, shutdowns, and outages of the FGD system are addressed by Requirement 19.

Req. 16, 21, 26 Utility MACT Emission Limits
[40 CFR 63 Subpart UUUUU]

The Utility MACT established emission limitations for hazardous air pollutants or their surrogates from coal and oil fired electric utility steam generating units.

For non-Hg HAP metals, sources may comply with an alternative particulate matter (PM) emissions limit as a surrogate. Past source emissions testing at this facility has consistently demonstrated compliance with the Utility MACT PM emission limit by a wide margin and the Utility MACT emission limit is far less stringent than the PM emission limit in RACT Order 97-2057R1, therefore TransAlta has chosen not to utilize the "emissions averaging" provisions and therefore does not need to develop an "emissions averaging plan". The Utility MACT PM emission limit and the PM emission limit in RACT Order 97-2057R1 were listed separately for informational purposes and because of the significant monitoring and recordkeeping requirements tied directly to the Utility MACT.

For HCl and HF emissions, sources may comply with an alternative SO_2 emissions limit as a surrogate. This is the choice TransAlta has chosen for the obvious reason that TransAlta must already operate an SO_2 CEMS to comply with the Acid Rain Program, and SWCAA 97-2051R1. CEMS data for this facility indicates that this facility consistently demonstrates compliance with the Utility MACT SO_2 emission limit by a wide margin, therefore TransAlta has chosen not to utilize the "emissions averaging" provisions and therefore does not need to develop an "emissions averaging plan".

The Hg emission limit in the Utility MACT is more stringent than the Hg emission limit TransAlta complies with under an off-permit agreement with Washington State signed May 2010. To comply with this off-permit agreement, TransAlta installed a Hg CEMS system that was certified to the Clean Air Mercury Rule standards in December 2009. In 2017 TransAlta replaced the CEMS with a sorbent trap monitoring system to demonstrate compliance with the Hg emission limit. A Hg process monitor provides the real-time feedback necessary to allow TranAlta to adjust operation of the Hg control system to assure compliance with the standard. Using the sorbent trap monitoring system, a single concentration value is assigned to each hour in the operating period (40 CFR 60 Subpart UUUUU Appendix A, Section 6.1.2). Concentration data is then converted to units of the emission standard (e.g. lb/TBtu) for each hour in the monitoring period using other CEMS data (e.g. diluent).

TransAlta has chosen not to utilize the "emissions averaging" provisions and therefore does not need to develop an "emissions averaging plan". For the Hg standard, sources must meet a more stringent Hg emission limit under the emissions averaging provisions.

Req. 22 Acid Rain Compliance Plan
[WAC 173-406-400, 40 CFR 72.40(a)]

40 CFR 72.9 and WAC 173-406-106 require that the Centralia Plant hold SO_2 allowances not less than the total annual emissions in tons of SO_2 from the affected units (EU-1, EU-2) at the Centralia Plant. The Centralia Plant received an initial allocation of allowances only for BW21 (EU-1) and BW22 (EU-2). The EPA may reallocate the number of allowances assigned to individual units and between units; therefore, annual allowance allocations may change in the future. The number of allowances actually held by a source in an Acid Rain affected unit account may differ from the number initially allocated by U.S. EPA as allowances are bought and sold on the open market to cover actual emissions.

Req. 27b - 31 Washington Department of Ecology BART Order
[Second Revision of BART Order No. 6426]

The BART Order established NO_X and NH_3 emission limits and associated operating, monitoring, recordkeeping, and reporting requirements for the coal fired boiler. The BART NO_X emission limit of 0.18 lb/MMBtu (30-day rolling average) is expected to be more stringent in all aspects than the previously established RACT permit limit of 0.30 lb/MMBtu (annual average for operation >360 MW); however the RACT limit in Req-27 was retained for the extremely unlikely scenario where overall NO_X emissions are less than 0.18 lb/MMBtu but NO_X emissions at operations above 360 MW were much higher.

Req. 34 Acid Rain NO_X Reduction Early Election for Group 1, Phase II Boilers
[WAC 173-406-106, 40 CFR 76.7(a)(1)]

The Phase II emission limit of 0.40 lb/million Btu was effective January 1, 2008.

Req. 36 Acid Rain Primary Monitoring Provisions
[40 CFR 75.10(a)]

40 CFR 75.10(a)(1) through (3) requires that an Acid Rain affected unit be equipped with continuous emissions monitoring systems with an automated data acquisition and handling system for measuring and recording SO_2, NO_X, and CO_2 emissions, respectively, discharged to the atmosphere. 40 CFR 75.10(a)(4) requires such units to be equipped with a continuous opacity monitoring system with an automated data acquisition and handling system for measuring and recording the opacity of discharged emissions.

Opacity

40 CFR 75.14(b) exempts units utilizing a wet flue gas pollution control system from the opacity monitoring requirements if the owner or operator can demonstrate that condensed water vapor is present in the exhaust stream and would impede the accuracy of opacity measurements. The Centralia Plant has provided ample demonstration that condensed water vapor is present in sufficient quantities to interfere with an opacity monitor and is therefore exempt from the requirement to continuously monitor opacity from the scrubber flues.

The gas stream leaving the scrubbers is saturated with water. As the flue gas inevitably cools, water condenses out of the gas stream forming steam and water droplets. The results of testing conducted during November 2001 (6 runs during scrubber performance test) and December 2001 (9 runs during initial RATA) indicated that the flue gas was supersaturated. Condensed water vapor is clearly visible through the sample ports at the test platform. All subsequent testing has supported this determination.

Gaseous Pollutant Monitoring at Bypass Stack

SWCAA 97-2051R1 requires monitoring of SO_2 emissions from both the bypass and scrubber flues. Acid Rain rules do not require direct monitoring at the bypass stack. This policy was detailed in question "17.6 – Revised" from the Acid Rain Policy Manual (December 2000) in addition to the Acid Rain rules promulgated May 1, 2002. Note that "Question 17.6 – Revised" is also found as "Question 16.4" in the 2013 version of the Part 75 Emissions Monitoring Policy Manual. The CEMS may be located upstream. When a certified monitoring system is not maintained on the bypass stack, the maximum potential emissions must be reported for bypass hours.

Req. 37 Utility MACT Tune-up Requirements

[40 CFR 63 Subpart UUUUU]

Subpart UUUUU requires initial and periodic tune-ups of the coal-fired boiler. The tune-up requirements are detailed in 40 CFR 63.10021(e) and Table 3 of 40 CFR 63 Subpart UUUUU. At the time this permit is being issued, TransAlta does not utilize neural network combustion optimization software; therefore the tune-up must be conducted every 36 months. In accordance with 40 CFR 63.10021(e) the initial inspection of the burners may be delayed beyond the October 13, 2015 compliance date and until the next "scheduled outage" if an outage is not scheduled before the compliance date. EPA describes this "scheduled outage" as a "major outage" in comment responses during rule development where there were comment regarding the long period of time necessary to erect scaffolding in the boiler. It is SWCAA's understanding that a short-term economic outage or an outage planned with little lead-time (for example to effect repairs) is not the type of "scheduled outage" discussed by this section of the rule. For the purposes of this requirement, SWCAA believes that a "scheduled outage" is a boiler outage where the boiler will be offline for a significant amount of time (e.g. weeks or months), and would usually be associated with planned inspections, major maintenance and/or repairs of the boiler interior.

Req. 38 Utility MACT Startup and Shutdown Provisions
[40 CFR 63 Subpart UUUUU]

Subpart UUUUU requires that all startups be conducted on "clean fuels". During startup and shutdown the facility typically uses ultra-low sulfur diesel, which is included in the definition of "clean fuels". In accordance with 40 CFR 63.10011(f) the facility must determine the "cleanest fuel" available on-site or accessible nearby for use during periods of startup or shutdown. However, the facility is required to utilize a "clean fuel", but not necessarily the "cleanest fuel" identified in 40 CFR 63.10011(f). See Response to Comment 67 in EPA's November 2014 Summary of Public Comments and Responses to the startup and shutdown reconsideration of 40 CFR 63 Subpart UUUUU.

The permittee is not precluded from considering a capital project to add natural gas firing capability. However New Source Review would be required before installing natural gas firing capability.

In the interests of streamlining the permit, the portions of the cited regulations that reference recordkeeping and reporting requirements were considered informational and not included in the permit requirement. All applicable recordkeeping and reporting requirements are included elsewhere in the permit.

Table 3 of Subpart UUUUU provides compliance options for two different definitions of "startup". The permittee is not committed to use either one. In option one, the ESPs and flue gas desulfurization (FGD) system must be engaged once coal is fired.

In option two, additional records must be generated and kept, clean fuels must be fired to the maximum extent possible during the startup period, the particulate control devices must be engaged within 1 hour of firing coal, and the Subpart UUUUU emission limits apply within 4 hours of producing electricity for any purpose. The FGD systems are not designed as PM control devices and are not necessary to meet PM emission limits; therefore, only the ESPs must be engaged within 1 hour of firing coal. SWCAA understands that operation of the FGD systems too early in the startup process when oil is being fired, and when PM levels have not been sufficiently reduced, is detrimental to both the short-term and long-term performance of the FGD system and would likely cause an increase in overall acid gas emissions. The US EPA provided some clarification of the startup requirements in an e-mail message dated August 13, 2015.

For Option 2, the end of "startup" was defined as ending when the EGU generates electricity that is sold or used for any other purpose (including on site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. The end of the startup period must be known to determine when "clean fuels" (ultra-low sulfur diesel in this case) no longer need to be fired to the "maximum extent possible". Based on the intent of the section and SWCAA's conversations with EPA staff, SWCAA believes that the end of startup could be much earlier (i.e. when all of the applicable pollution control devices have been engaged). At that point there is no need to continue firing "clean fuels" for the purpose of minimizing emissions and the facility should be able to achieve compliance with all applicable emission limits.

With respect to firing clean fuel to the "maximum extent possible", SWCAA understands this requirement to impose a duty to fire as much clean fuel as necessary to enable the applicable emission control equipment to be engaged as soon as possible, but no later than 1 hour after, coal is fired.

Req. 39 Good Air Pollution Control Practices

[40 CFR 63.9991(c)(2), 63.1000(b), SWCAA 97-2057R1]

This requirement as it originates from SWCAA 97-2057R1 is meant to require reasonable practices to reduce emissions below the short-term emission limits provided in SWCAA 97-2057R1 when possible, and optimize use of the emission control equipment. The following paragraphs describe good air pollution control practices for minimization of SO_2, NO_X, and PM emissions from the coal-fired boiler for compliance with the requirements from SWCAA 97-2057R1.

Sulfur Dioxide

The SO_2 emission control equipment is the Flue Gas Desulfurization (FGD) system or scrubber. Good air pollution control practice is to utilize recycle pumps as necessary to maintain SO_2 as low as practicable without allowing the SO_2 CEMS indication to drop to or below zero (below zero indications are possible due to minor instrument drift). A small amount of SO_2 must be maintained in the flue gas to assure that the gypsum that is produced is of marketable quality for manufacturing, and to prevent degradation or damage to the desulfurization system from scaling. If all SO_2 in the flue gas is reacted, the residual limestone can, in a short time period, cause scaling in the reaction vessel leading to reduced scrubbing efficiency and mechanical failure.

The original design specifications for the scrubber specify that three of the four recycle pumps would be in operation at any one time. The fourth recycle pump would be maintained as a maintenance spare and backup. The specification was based on the use of high sulfur coal from the Centralia Mine. When the plant is using low sulfur coal from the Powder River Basin, SO_2 can be maintained at a minimum level with the use of less than three recycle pumps.

In addition to maintaining minimum SO_2 levels, at times it may not be possible to operate the design number of recycle pumps and spray levels due to operational problems including when:

1. Equipment problems require two pumps off-line for maintenance or repair activities; and
2. Equipment problems downstream of the scrubber (e.g. vacuum belt filter malfunctions, problems with reaction tank oxidation blowers) or upstream of the scrubber (e.g. reagent pump or ball mill failures) limit reagent addition or gypsum removal.

Such events should be reported as an upset condition and will be reviewed on an individual basis.

Nitrogen Oxides

The NO_X emissions control system is good boiler combustion practices, low NO_X burner modifications on the boiler, and the SNCR system. NO_X control through good combustion practices is significantly different than add-on SO_2 control. This form of NO_X control is an integral part of the combustion process. If the boiler is operated to minimize NO_X emissions, combustion efficiency decreases to the point of limiting electrical power output, increases coal combustion/megawatt which increases emissions of other pollutants (SO_2, PM, CO and VOCs) and increases slagging, sootblowing and maintenance costs from increased boiler tube repairs. Based on current information, good air pollution control practice for NO_X is balancing the varied factors and maintaining emissions below the RACT and BART limitations.

Particulate Matter

The particulate matter (PM) emissions control systems are the two tandem electrostatic precipitators in series. In addition, the FGD system removes additional PM through the scrubbing process. Maintaining good precipitator performance is important in order to maintain the quality of the gypsum by-product necessary for sale for use in wallboard.

Req. 41, 42 Boiler MACT Requirements for Auxiliary Boiler

[40 CFR 63 Subpart DDDDD]

Boilers in the "limited use" subcategory are those boilers with a federally enforceable annual average capacity factor of no more than 10 percent. The Auxiliary Boiler (EU-3) is a startup boiler; therefore, a low capacity utilization would be expected. Section 45 of SWCAA 97-2057R1 expressly limited the total amount of fuel this boiler can fire to 600,000 gallons per year. The boiler has a rated heat input capacity of 170 MMBtu/hr. Assuming a fuel oil heat input capacity of 138,000 Btu/gallon (from 40 CFR 98), the 600,000 gallon per year limitation is equivalent to a capacity factor of approximately 5.6%. Both the 600,000 gallon per year limitation and the 10 percent capacity factor threshold are on a calendar year basis. Boilers in the "limited use" subcategory are subject to the general requirement to operate consistent with good air pollution control practices and the requirement to conduct initial and periodic tune-ups rather than specific emission limits.

Req. 43 Pug Mill Opacity

[SWCAA 01-2403]

This requirement represents BACT for control of fugitive particulate matter from this source at the time of permitting (2001). The only potential point of emissions from this source is fugitive during the transfer to trucks. The pug mill mixing function is conducted through the use of the two UCC Model 6050 Pin Paddle Mixers installed in 2009.

Req. 44 Turbine Lube Oil Mist Eliminators Opacity

[SWCAA 01-2403]

This requirement represents BACT for control of visible emissions/lube oil mist from this source at the time of permitting (2001). The manufacturer literature for the Advanced Environmental Systems mist eliminator guarantees opacity levels of 5% or less. On-site observations have demonstrated that visible emissions from this source do not exceed 5%. Using the conservative assumption of a 99.5% control efficiency (provided by Advanced

Environmental Systems on a particle count basis), and 8,760 hours of operation per year, each turbine lube oil mist eliminator will emit up to 0.1 pounds of lube oil mist per year.

Req. 45 - 47 Control of Particulate Matter from Coal Unloading
[SWCAA 11-2972]

The requirements in Air Discharge Permit SWCAA 11-2972 represent BACT for control of particulate matter (coal dust) from the unloading of coal from rail cars at this facility.

Annual emissions of PM_{10} from the Coal Unloading Facility are to be calculated using the following equation (found in Section 6 of the Technical Support Document for Air Discharge Permit 11-2972) for each transfer point:

$$E = k(0.0032)\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}$$

Where: E = emission factor (lbs PM per ton coal unloaded)
k = particle size multiplier (dimensionless). k=1.0 for PM, 0.35 for PM_{10}, 0.11 for $PM_{2.5}$
U = mean wind speed (miles per hour)
M = coal moisture content (%)

A control factor of 90% is applied to transfer points utilizing high pressure wet suppression to control fugitive dust (some pre-existing transfer points may be uncontrolled).

Req. 48, 49 Control of Particulate Matter from FGD Bleed Treatment Lime Storage Silo
[SWCAA 05-2636]

Air Discharge Permit SWCAA 05-2636 was written in response to an Air Discharge Permit (ADP) application for installation of a new hydrated lime storage silo. This silo was installed as part of a project to remove boron and zinc from the flue gas desulfurization (FGD) system scrubbing liquor. These requirements represent BACT for control of particulate matter (hydrated lime) from the pneumatic loading of hydrated lime into the silo.

Req. 50, 51 Control of Particulate Matter from Journal Shop
[SWCAA 08-2779]

Air Discharge Permit SWCAA 08-2779 was written in response to an Air Discharge Permit (ADP) application for installation of a larger capacity cartridge filtration system to control welding fumes exhausted from the Journal Shop. The purpose of the project was to reduce worker exposure to welding fumes. The requirements in Air Discharge Permit were written to implement BACT and protect ambient air quality.

Req. 52 - 58 Engine Requirements Originating from 40 CFR 63 Subpart ZZZZ
[40 CFR 63 Subpart ZZZZ]

40 CFR 63 Subpart ZZZZ established emission limitations and operating requirements for various categories of reciprocating engines. The engines at the coal plant fall into two categories of engines regulated by Subpart ZZZZ. All of the applicable requirements for these engines have been included in the Air Operating Permit.

One requirement requires that engines be maintained "according to the manufacturer's emission-related written instructions or develop a maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions." The permittee submitted a maintenance plan for their "existing" stationary diesel engines to SWCAA on August 8, 2011. The portions of the maintenance plan relevant to engine emissions are included in Appendix C and are applicable requirements as described in Req-54.

For the purposes of this requirement, emergency operation of the fire pump is any operation necessary in response to a fire.

Req. 55, 57, 58, 61, 62, 65 Engine Requirements Originating from 40 CFR 60 Subpart IIII
[40 CFR 63 Subpart IIII]

40 CFR 63 Subpart IIII established emission limitations and operating requirements for various categories of "new" reciprocating engines. Where the requirements under Subpart IIII are the same as for 40 CFR 63 Subpart ZZZZ, the terms have been streamlined and applied to groups of engines. All of the applicable requirements for these engines have been included in the Air Operating Permit.

Req. 59 - 65 Requirements for the Coal Unloading Facility Emergency Diesel Sump Pump Engine
[40 CFR 63 Subpart ZZZZ, 40 CFR 60 Subpart IIII, and SWCAA 11-2972]

The Coal Unloading Facility Emergency Diesel Sump Pump Engine was installed as a "new" engine for the purposes of 40 CFR Subpart ZZZZ, therefore the engine is required to comply with Subpart ZZZZ by meeting the requirements of 40 CFR 60 Subpart IIII. The engine underwent New Source Review, resulting in the issuance of Air Discharge Permit 11-2972. Air Discharge Permit 11-2972 contained all of the applicable requirements from 40 CFR 60 Subpart IIII and additional requirements originating from SWCAA's general regulations and the minor New Source Review process.

In a June 28, 2011 amendment to 40 CFR 60 Subpart IIII, EPA changed section 60.4211(a) to allow owners/operators of stationary engines to deviate from manufacturer's written emissions-related instructions if they complied with additional recordkeeping and conducted an initial source test to demonstrate compliance with the applicable emission standards. These alternative requirements are included in section 60.4211(g). This compliance option is not detailed in the permit because the permittee has indicated that they will follow the manufacturer's written instructions.

For the purposes of this requirement, emergency operation is any operation necessary because the electrical water pump at the Coal Unloading Facility has unexpectedly failed. If the electrical water pump fails, it must be repaired as soon as practical. Operation of the Coal Unloading Facility Diesel Sump Pump Engine because the electrical water pump was not repaired as soon as practicable, would not be considered emergency operation.

Compliance with the annual emission limits for the Engine in Condition 5 of SWCAA 11-2972 is to be determined by multiplying the hours of operation by the emission factors presented in the Technical Support Document for SWCAA 11-2972 unless new emission factors are provided by the manufacturer or developed through source testing.

Req. 66 - 71 Requirements for Fire Pump Engine and Emergency Diesel Generator 2
[SWCAA 16-3188]

The requirements for these two engines appear together in many places because they are both subject to 40 CFR 60 Subpart IIII and are regulated by Air Discharge Permit 16-3188. Compliance with the annual emission limits for the Fire Pump Engine must be determined by multiplying the hours of operation by the emission factors presented in the Technical Support Document for SWCAA 16-3188 unless new emission factors are provided by the manufacturer or developed through source testing. These emission factors are listed in the explanation of M27.

Req. 72 – 76 Requirements for the Material Handling Systems Associated with the Mercury Control System and Fly Ash Bins
[SWCAA 11-2984]

Air Discharge Permit 11-2984 was written to approve material handling modifications necessary to implement an activated carbon injection (ACI) mercury control system on the two coal-fired boilers (one of which retired at the end of 2020). The fly ash bin baghouse exhausts are subject to the Compliance Assurance Monitoring (CAM) requirements of 40 CFR 64, and each utilize a baghouse leak detection monitor. This monitoring (along with periodic source emissions testing) is expected to provide an adequate assurance of compliance with the permitted emission limits.

Compliance with the annual emission limits in Condition 1 of SWCAA 11-2984 is to be determined by multiplying the hours of operation by the design flow rate and an emission concentration of 0.005 gr/dscf unless new emission factors are developed through source testing.

Filter	Rated Flow
SEA System 1	1,130
SEA System 2	1,130
Sorbent Silo 1	350
Sorbent Silo 2	350
Fly Ash Bin 11	14,730
Fly Ash Bin 12	14,730
Fly Ash Bin 14	14,730
Fly Ash Bin 14 Air Slide to Bin 11 Air Slide	900

Filter	Rated Flow
Fly Ash Bin 11 to Weigh Hopper Air Slide	900
Fly Ash Bin 14 to 6050 Air Slide	600

Condition 3 of SWCAA 11-2984 requires that each emission unit be operated properly. It will be presumed that the equipment is being operated properly unless otherwise indicated by an inspection or excess emissions. In that case, equipment operating manuals and maintenance records may be reviewed to determine if the equipment is being improperly operated or maintained.

Req. 77 – 81 Requirements for the Fly Ash Weigh Bin
[SWCAA 12-3016]

Air Discharge Permit 12-3016 was written to approve a new baghouse for the Fly Ash Weigh Bin to replace the existing baghouse on the fly ash weigh bin (operated by Lafarge North America at the time of permitting), and the relatively new "Fly Ash Bin 11 to Weight Hopper Air Slide Filter" (operated by TransAlta). The replacement baghouse filters dust from air collected from the fly ash loading spout and air vented to the fly ash bin from the No. 11 Air Slide and the No. 12 Air Slide.

Compliance with the annual emission limits in Condition 1 of SWCAA 12-3016 is to be determined by multiplying the hours of operation by the design flow rate and an emission concentration of 0.002 gr/dscf until or unless new emission factors are developed through source testing.

Req. 82 – 88 Requirements for Fine Coal Handling
[SWCAA 14-3093]

Air Discharge Permit 14-3093 was written to approve coal mine waste reprocessing activities and fine coal recovery. Only fine coal handling will occur at TransAlta Centralia Generation.

Annual emissions of particulate matter from the transfer of fine coal onto the coal stockpile are to be calculated using the following equation (found in Section 6 of the Technical Support Document for Air Discharge Permit 14-3093) for each transfer point:

$$E = k(0.0032)\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}$$

Where: E = emission factor (lbs PM per ton coal unloaded)
k = particle size multiplier (dimensionless). k=1.0 for PM, 0.35 for PM_{10}, 0.11 for $PM_{2.5}$
U = mean wind speed (miles per hour)
M = coal moisture content (%)

Meteorological data indicates that the mean wind speed at this site is 4 miles per hour. It was assumed that wet suppression will provide for 90% control of fugitive dust emissions. There is only one transfer point that is not fully enclosed (transfer to the TransAlta Generation stockpile). The transfer to the TransAlta Generation stockpile will be equipped with high-pressure wet suppression that will be used if visible emissions are observed. It is expected that the fine coal moisture will be too high to generate significant dust.

Req. 88 – 92, 95, 96 Minor New Source Review Permit and Subpart ZZZZ Requirements for Black Stop Generator Operation

Requirements removed – the Black Stop Generator Engine was permanently retired at the end of 2020.

Req. 93, 94 PSD Permit for Combustion Turbine Facility (Black Stop Diesel Generator Engine)

Requirements removed – the Black Stop Generator Engine was permanently retired at the end of 2020.

VI. EXPLANATION OF OBSOLETE AND FUTURE REQUIREMENTS

1. Obsolete Regulatory Orders/Permits

SWCAA issued eight Orders and Air Discharge Permits to the permittee between 1972 and 1974 in response to a particulate matter control equipment testing program and Air Discharge Permit applications submitted for installation or modification of such equipment and for operations at the source. Seven Orders were issued to the permittee between 1987 and 1991 regarding the averaging period for the SWCAA SO_2 emission standard and a variance request by the source. These seven Orders are no longer applicable as described below. From 1995 through early 1998, three Regulatory Orders concerning Reasonably Available Control Technology (RACT) requirements were issued to the permittee, two of which are no longer applicable as described below.

A SWCAA Order dated December 11, 1972 required the PM emission level of 0.06 gr/dscf not to be exceeded at any time, and also established maximum operating levels during compliance testing of both units. An Order dated April 13, 1973 approved installation of additional ESP collection area and required that additional sections be designed and installed to control emissions to 0.06 gr/dscf. A SWCAA Order dated April 26, 1973 specified objectives of a particulate matter emission testing program, allowed operation at maximum output during a specified test schedule for Unit 1, and reiterated the 0.06 gr/dscf emission limit in the December 11, 1972 Order. An Order dated May 4, 1973 approved operation of Unit 2 at maximum output during a scheduled particulate matter emissions test and listed the objectives of the test program. A May 22, 1973 Order extended the test schedule for Unit 2. A SWCAA Order dated June 11, 1973 approved full output operation of Unit 1, and, not to be exceeded at any time, the particulate matter emission level of 0.06 gr/dscf.

These Orders were effectively replaced by a subsequent SWCAA Order (dated February 7, 1974 and revised on February 22, 1974) that approved installation of the Lodge-Cottrell ESPs in series following the original ESPs on both Units 1 and 2. This February 1974 Order approved continued operation at an emission level not to exceed 0.06 gr/dscf and required

demonstration of satisfactory equipment performance within three months after startup of the new ESPs. Administrative Order 74-38 established a high-load testing schedule for Unit 2 not to exceed ten days commencing May 6, 1974. Although these Orders were not explicitly superseded until SWCAA 97-2057R1 was issued, the Orders dealing only with the testing program to improve and evaluate particulate matter collection became moot with the approval and subsequent performance demonstration of the Lodge-Cottrell ESPs.

The Centralia Plant disagreed with SWCAA's authority to establish via the February 1974 Order an emission limit more stringent than the state standard for particulate matter, 0.1 gr/dscf. SWCAA established the 0.06 gr/dscf emission limit consistent with "advances in the art" (the term that predates BACT) to not allow degradation of the control equipment and ensure meaningful emission reductions as intended under the Clean Air Act. Although all previous Orders have been superseded by Section 49 of SWCAA 97-2057R1, the 0.06 gr/dscf emission limit based on "advances in the art" was effective until the RACT limit of 0.010 gr/dscf become the applicable requirement for particulate matter emissions after December 31, 2001.

Order of Violation SWCAA 87-934 was issued for violations of the 1,000 ppm SO_2 emission limit based on average daily coal sulfur analyses, and required the permittee to implement coal analysis at twenty minute intervals, perform sampling of SO_2 emissions, and correlate the sampling results with the coal analyses. The Order suspended a civil penalty provided that no additional violations of the SO_2 emission standard occurred for one year. Stay of Order of Violation SWCAA 87-934-STAY stayed for up to 18 months from September 21, 1987 the requirements in SWCAA 87-934 for coal analysis and SO_2 emission sampling, and the civil penalty.

Order, Withdrawal of Stay, and Modification of Order of Violation SWCAA 88-934 required the Centralia Plant to install continuous SO_2 and O_2 emissions monitors, install ambient air quality monitors at three sites near the facility, blend and wash the coal supplied to its boilers, conduct a feasibility study of lime injection multiple burner technology to reduce SO_2 emissions, and comply with the SO_2 emission limit of 1,000 ppm averaged over a one week period. This Order, issued on February 24, 1988, withdrew the coal analysis and SO_2 emission sampling provisions and the civil penalty assessed by SWCAA 87-934. SWCAA 88-934 was amended by Variance and Modification of Order SWCAA 88-934B which granted a variance from the 1-hour averaging period of the SO_2 emission standard and established a weekly averaging period effective May 25, 1988 through November 25, 1989. SWCAA 88-934B required measured SO_2 emissions to be corrected to a dry basis, installation of meteorological monitoring equipment to be operated from October 1, 1988 through September 30, 1989, modeling of SO_2 emissions by an EPA approved dispersion model, and other minor modifications to 88-934.

SWCAA 88-934C Variance Renewal and Modification of Order extended the variance for weekly instead of hourly averaging of SO_2 emissions until November 25, 1990, extended the collection of ambient monitoring data through September 30, 1990, and modified the ambient air monitoring provision to require two rather than three sites. SWCAA 90-934D Variance Renewal and Modification of Order extended the variance for weekly instead of hourly averaging of SO_2 emissions until the earlier of November 25, 1991 or the date on which practicable means for the adequate abatement or control of SO_2 emissions from the Centralia

Plant become known, available, and implementable. The Order required that collection of ambient meteorological monitoring data extend through September 30, 1991, and that the permittee report to SWCAA the results of its dispersion modeling by December 31, 1991. Effective on April 5, 1991, SWCAA 90-934E Withdrawal of Petition, Surrender of Variance, and Order terminated the variance, meteorological monitoring, ambient monitoring, dispersion modeling, and modeling report provisions of SWCAA 90-934D and 88-934.

SWCAA 90-934E Withdrawal of Petition, Surrender of Variance, and Order (issued on April 5, 1991) revoked an earlier Variance and restored compliance with the SO_2 standard over a 1-hour averaging period. It also established a procedure for determining compliance with the hourly SO_2 standard which defined an "excess SO_2 emission day" as 3 or more unique excess SO_2 emission hours during any continuous 24-hour period in the month, and an "SO_2 emission violation" as 3 or more unique excess SO_2 emission days occurring in a calendar month. SWCAA 97-2057R1 supersedes Order No. SWCAA 90-934E along with its SO_2 compliance procedure.

Regulatory Order to Establish RACT SWCAA 95-1787 established a plant-wide annual average emission rate limit and total tonnage limit for SO_2 and specified compliance dates for achieving these emission limits. This Order was appealed by a third party to the Pollution Control Hearings Board (PCHB). SWCAA issued Order of Withdrawal SWCAA 96-1872 to withdraw SWCAA 95-1787 while pursuing additional SO_2 emission reductions through a collaborative process. However, the PCHB ruled SWCAA 96-1872 was an amendment to the original RACT Order, and therefore the RACT Order (95-1787) was still in effect. The SWCAA Board then approved Resolution 1996-8 on September 18, 1996 which withdrew both SWCAA 95-1787 and 96-1872, a decision later upheld by the PCHB.

An EPA Order on Consent was issued on May 18, 2001 to allow the permittee to commence construction of the Combustion Turbine Facility prior to issuance of a PSD permit. This order became obsolete upon issuance of PSD permit No. PSD-01-01.

PSD-01-01 was issued on February 22, 2002 for construction of the Combustion Turbine Facility. This PSD permit dealt only with those PSD pollutants with emissions at or above the PSD significance threshold (PM and NO_X). SWCAA Air Discharge Permit 01-2350 was issued on May 30, 2001 to address emissions of all other pollutants. Air Discharge Permit 01-2350 was superseded by Air Discharge Permit SWCAA 01-2350R1, issued on May 6, 2002. Air Discharge Permit SWCAA 01-2350R1 was written in response to an Air Discharge Permit application requesting an increase in the combustion turbine facility's sulfur oxides emission limits.

The permittee became aware on July 12, 2002 that the auxiliary boiler that was ultimately installed at the Combustion Turbine Facility was not the one approved by PSD-01-01 or Air Discharge Permit SWCAA 01-2350R1. PSD-01-01 and Air Discharge Permit SWCAA 01-2350R1 approved the 4.18 MMBtu/hr Cleaver-Brooks boiler specified in the Notice of Construction (NOC) applications for those permits. The permittee notified SWCAA of this fact on the next business day (July 15, 2002).

On July 22, 2002 SWCAA issued Consent Order SWCAA 02-2422 to address the issue. The consent order was signed by Ms. Linda Chambers for TransAlta Centralia Generation,

LLC on July 24, 2002. This consent Order became obsolete with the submittal of a Notice of Construction L-505 on August 15, 2002 (submittal of this notice satisfied the last requirement in the consent order).

PSD-01-01 was superseded by PSD-01-01 Amendment 1 on January 30, 2003. The permit amendment was made to approve the existing BHP Auxiliary Boiler.

Air Discharge Permit 01-2350R1 was superseded by Air Discharge Permit 01-2350R2 on October 15, 2003. Air Discharge Permit 01-2350R2 was written in response to Air Discharge Permit application L-505 for approval of the existing BHP Auxiliary Boiler.

PSD-01-01 Amendment 1 was superseded by PSD-01-01 Amendment 2 on June 11, 2004. The permit amendment was made to clarify the RATA frequency requirements.

Air Discharge Permit 01-2350R2 was superseded by Air Discharge Permit 01-2350R3 on May 12, 2005. Air Discharge Permit 01-2350R3 was written to make the source testing and RATA frequencies in the minor source permit consistent with the RATA frequencies in PSD-01-01 and the Acid Rain Program rules.

Air Discharge Permit 05-2612 was issued on July 15, 2005 for the addition of a coal unloading hopper to the West Coal Unloading Facility. Air Discharge Permit 05-2612 was superseded by Air Discharge Permit 07-2712 on February 7, 2007. Air Discharge Permit 07-2712 was written in response to a request for installation of surge capacity to the West Coal Unloading Facility. Air Discharge Permit 07-2712 was superseded by Air Discharge Permit 07-2749 on September 26, 2007. Air Discharge Permit 07-2749 was written in response to a request for modification of the West Coal Unloading Facility operating limitations and installation of the Coal Unloading Facility. Air Discharge Permit 07-2749 was superseded by Air Discharge Permit 11-2972 on April 14, 2011. Air Discharge Permit 11-2972 was written in response to a request to install a diesel-fired emergency water pump at the Coal Unloading Facility.

Air Discharge Permit 01-2350R3 was superseded by Air Discharge Permit 01-2350R4 on January 18, 2008. Air Discharge Permit SWCAA 01-2350R4 was written in response to an ADP application submitted by the permittee to eliminate the 1.5 ppmvd @ 15% O_2 (8-hour average) CO emission limit (BACT was re-evaluated) for the combustion turbines. The 3.0 ppmvd @ 15% O_2 (1-hour average) was retained.

Best Available Retrofit Technology (BART) Order No. 6426 was issued June 18, 2010 by the Washington Department of Ecology as implementation of Washington's visibility program (WAC 173-400-151) which is implemented consistent with the federal visibility protection program (40 CFR Part 51, Subpart P). Order No. 6426 established a NO_X emission limit of 0.24 lb/MMBtu for the coal fired boilers and a minimum coal quality requirements. EPA approved the SIP submission containing this BART submission in a Federal Register notice dated December 6, 2012.

BART Order No. 6426 was superseded by the First Revision of BART Order No. 6426 issued December 13, 2011. The First Revision of BART Order No. 6426 was issued to implement new requirements from a 2011 law (Washington Engrossed Second Substitute Senate Bill 5769). Under this law the Governor is required to enter in a "memorandum of agreement" with the plant owner on behalf of Washington State to install and operate selective non-catalytic reduction (SNCR) to provide additional control of NO_X emissions no later than January 1, 2013. The Memorandum of Agreement was finalized December 23, 2011. The law also requires one boiler to comply with the greenhouse gas emission performance standard in RCW 80.80 by December 31, 2020 and the second boiler by December 31, 2025. These requirements were included in the First Revision of BART Order No. 6426. Approval of this revision into the Washington SIP was published in the Federal Register on December 6, 2012.

The First Revision of BART Order No. 6426 was superseded by the Second Revision of BART Order No. 6426 issued July 29, 2020. This revision was made to address problems with, and caused by, the SNCR system. The revision reduced the NO_X limit for the longer-lived unit from 0.21 lb/MMBtu to 0.18 lb/MMBtu while removing the prescriptive SNCR operating requirements. Approval of this revision into the Washington SIP was published in the Federal Register on May 7, 2021.

Air Discharge Permit 11-2996 was issued November 11, 2011 for installation and operation of the Pump-05 Engine. Air Discharge Permit 11-2996 was superseded on October 18, 2012 by Air Discharge Permit 12-3035. Air Discharge Permit 12-3035 was issued for installation of a new fire pump engine that may also be used to supply non-emergency water pumping during plant maintenance events. The permit conditions related to the engines addressed in Air Discharge Permit 11-2996 were carried forward in Air Discharge Permit 12-3035.

Air Discharge Permit 12-3035 was superseded by Air Discharge Permit 16-3188 on June 1, 2016. Air Discharge Permit 16-3188 was written for approval of a nonroad engine and an emergency generator engine to replace the Emergency Diesel Generator 2 engine.

2. Initial Testing Requirements for Limestone Ball Mill

The initial testing requirements of 40 CFR 60.18 for the Limestone Ball Mill (consisting of opacity observations as specified in 40 CFR 60 Subpart OOO) were completed on October 24, 2007.

3. Acid Rain Requirements

The general Acid Rain recordkeeping provisions of 40 CFR 75.50 are no longer valid as of January 1, 1996, and are replaced by the general recordkeeping provisions of 40 CFR 75.54. The Acid Rain Program provided an optional set of recordkeeping requirements with only slightly different provisions prior to January 1, 1996, but disallows their use from January 1996 onward.

4. Future NSPS/MACT/NESHAP Standards

None

5. Future Coal-Fired Boiler Shutdown Requirements

Condition 3 of the Second Revision of Bart Order No. 6426 requires that one coal-fired unit permanently cease burning coal no later than December 31, 2020, and the second permanently cease burning coal no later than December 31, 2025. These requirements would not apply if the Department of Ecology determines as a requirement of state or federal law or regulation that selective catalytic reduction (SCR) technology must be installed on either coal fired boiler. This requirement implements requirements in RCW 80.80 as amended in 2011. RCW 80.80 requires that the coal fired boilers meet a greenhouse gas performance standard that is the lower of 1,100 lbs/MW-hr or the average available greenhouse gas emissions output as determined under RCW 80.80.050. The output determined under RCW 80.80.050 is published by the Washington Department of Commerce in WAC 194-26 and was 925 lbs/MW-hr effective April 6, 2013. These standards cannot be met by these boilers without the addition of CO_2 capture equipment or shutdown.

VII. EXPLANATION OF MONITORING AND RECORDKEEEPING TERMS AND CONDITIONS

M1. General Recordkeeping

This recordkeeping section is taken directly from SWCAA 97-2057R2 Sections 26 and 29, SWCAA 05-2636, SWCAA 08-2779, SWCAA 11-2072, SWCAA 14-3093, and WAC 173-401-615(2). Sections (a) through (d) were added to clarify specific requirements. Under K1(c)(i) of the permit "equipment out of service" is limited to SO_2 emission control equipment, and "upset conditions" are limited to pollution control equipment or equipment that would directly impact SO_2 emissions.

M2. Visible Emission Monitoring

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from SWCAA 400 and the specific requirements drawn from SWCAA 97-2057R1, SWCAA 01-2403, and SWCAA 14-3093. The general requirements in SWCAA 400 do not directly establish any specific regime of monitoring or recordkeeping. Consequently, SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615 where no other monitoring is required by an applicable requirement. M1 is designed to provide periodic assurance of compliance and record any necessary corrective action. This requirement pertains to the visual technique for evaluating visible emissions, not the continuous monitor method. Demonstration of compliance is required in some cases via visible emissions evaluation. An individual educated in the procedures of visible emission observation and evaluation is to perform the periodic compliance assurance monitoring. A Certified Observer, certified in accordance with EPA Method 9, is to perform the visible emission observations based on the method in Appendix A of the Air Operating Permit.

M3. Particulate Matter Emissions Monitoring

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from SWCAA 400 and specific requirements drawn from SWCAA 05-2636, SWCAA 11-2972, SWCAA 12-3016, and SWCAA 14-3093. A particulate matter exhaust standard of 0.1 gr/dscf applies to both combustion and non-combustion emission units. These requirements do not directly establish any specific regime of monitoring or recordkeeping. Consequently, SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615 where no other monitoring is required by an applicable requirement. M2 is designed to assure compliance through periodic facility inspections and prompt corrective action within 2 hours of observing particulate matter fallout or excess visible emissions whenever necessary. The permittee is required to resolve the particulate matter fallout or excess emissions problem within 24 hours of initial discovery, or notify SWCAA by the next working day of progress made towards resolution. Excess emissions are emissions above the state standard or permit limit. The site inspection and visual observation are surrogate methods for assessing the relative emissions from non-combustion emission units EU-4, EU-5, and EU-6 that have demonstrated emissions well below the general standards.

Both Coal Plant units (EU-1 and EU-2) are equipped with electrostatic precipitators that remove over 99.5% of the particulate matter from coal combustion leaving emission concentrations less than one-tenth of the standard in Req-9. Combustion of fuel oil in the auxiliary boiler (EU-3) does not produce emission concentrations near this standard either. Monitoring for the standards in Reqs-9 and 11 makes use of observations that will readily indicate if control equipment or material handling management practices are seriously deficient. The site inspection and visual observation are surrogate methods for assessing the relative emissions from emission units EU-1, EU-2, and EU-3 that have demonstrated emissions well below the general standards.

Condition 8 of Air Discharge Permit SWCAA 11-2972 requires that the water pressure of the spray/fog nozzles be maintained at 80 psig or greater during operation of the coal unloading facility, however no monitoring of the water pressure was required (although a visual inspection is required monthly). Consequently, SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615 that require the spray pressure to be measured during the monthly inspection and recoded in accordance with Section VIII K1(a).

M4. Fugitive Emissions Monitoring

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from SWCAA 400 and the specific requirement from SWCAA 01-2403 to control fugitive dust from operation of the fly ash pugmill. SWCAA 400 does not directly establish any specific regime of monitoring or recordkeeping for these standards. Consequently, SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615 for those general requirements. M3 is designed to assure compliance through a combination of periodic facility inspections, use of

reasonable precautions and good work practices, and prompt corrective action whenever necessary.

M5. Complaint Monitoring

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from SWCAA 400 and specific requirements in SWCAA 01-2350R4, SWCAA 11-2972, SWCAA 12-3016, and SWCAA 16-3188. SWCAA 400, SWCAA 01-2350R4, Condition 3 of SWCAA 12-3016, and SWCAA 16-3188 do not directly establish any specific regime of monitoring or recordkeeping for these requirements. Consequently, for these rules SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615. M4 is designed to assure compliance through prompt complaint response and corrective action whenever necessary.

M6. Operations Monitoring

The requirements cited in this monitoring section are "gap-filling" monitoring under the authority of WAC 173-401-615(1). No requirements rely solely on this monitoring condition to assure compliance. These requirements ensure sufficient monitoring where the applicable rule or permit does not provide an adequate assurance of compliance with the applicable requirement. M5 is designed to assure compliance through operation of pollution control equipment according to manufacturer specifications and/or consistent with good engineering and maintenance practices, and by taking corrective action whenever necessary. Emissions control equipment is operated to minimize overall long-term emissions. Manufacturer specifications should be followed except in instances where alternative practices are equivalent or better. The goal is to maintain performance rather than follow exact manufacturer specifications.

M7. Coal Plant SO_2 General Standard Monitoring

This monitoring requirement in combination with M8 is used to provide a reasonable assurance of compliance with the general SO_2 emission concentration limit contained in SWCAA 400. SWCAA 400-040(6) limits the emission of sulfur dioxide from combustion sources to a maximum of 1,000 ppmv corrected to a specified oxygen percentage as noted in SWCAA 400-050(3). The combustion sources at this facility combust pulverized coal and fuel oil (No. 2 distillate diesel oil). EU-3 is fueled exclusively with fuel oil, and its monitoring requirement consists only of quarterly certification of fuel sulfur content. A CEM mandated by the Acid Rain Program continuously measures the SO_2 concentrations of the flue gasses emitted by EU-1 and EU-2 and determines 60-minute averages (see M9).

SWCAA 97-2057R1 requires the use of coal sulfur content sampling to fill in missing CEM data periods, and certification of fuel oil burned in the auxiliary boiler and BW21 and BW22 but does not detail the frequency of such monitoring. This requirement provides the explanation of the minimum monitoring necessary to comply with these requirements. Monitoring of coal sulfur content by monthly composite sampling is required for comparison and potential backup purposes in the event of missing CEMS data. The conversion between fuel sulfur content and SO_2 concentration relies upon an approximate linear relationship based

on operational experience with a coal sulfur content of 1% by weight corresponding to an SO_2 bypass stack concentration of 1,000 ppm. Quarterly certification of fuel oil sulfur content is required to demonstrate compliance with the 1,000 ppm requirement, but the frequency of each sulfur content determination depends on the fuel suppliers' shipments and is not a continuous monitoring requirement. The maximum level of sulfur in the fuel oil consumed is 0.5% by weight. The following calculation demonstrates how the 1,000 ppmvd sulfur dioxide limit cannot be exceeded when burning fuel oil with a sulfur content of 0.5% or less:

$$\text{ppm}\,SO_2 @ 7\%O_2 = \frac{7.206\,\text{lb oil}}{\text{gallon}} \bullet \frac{1\,\text{gallon}}{0.141\,\text{MMBtu}} \bullet \frac{0.005\,\text{lbS}}{\text{lb oil}} \bullet \frac{\text{lb}\cdot\text{mole}}{32\,\text{lbS}} \bullet \frac{385\,\text{scf}}{\text{lb}\cdot\text{mole}} \bullet \frac{\text{MMBtu}}{9{,}190\,\text{dscf}} \bullet \frac{(20.9 - 7\%O_2)}{20.9} \bullet 10^6$$

$$\text{ppm}\,SO_2 @ 7\%O_2 = 22.2$$

M8. Coal Plant Stack Sampling Monitoring Requirements

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from SWCAA 400, the specific emission limits contained in SWCAA 97-2057R1, Second Revision of BART Order No. 6426 and 40 CFR 63 Subpart UUUUU. SWCAA 400-052 specifies a frequency for source testing of all applicable combustion units, which are those which emit 100 tons per year or more of NO_X, CO, particulate matter, SO_2, or VOC. Emissions tests are required every two calendar years for those pollutants for which the source emits 100 tons per year or more. The use of continuous emissions monitors is an acceptable alternative to the specified sampling schedule. The permittee operates CEMS at each stack for NO_X and SO_2 that meet Acid Rain requirements. In addition, CO is continuously monitored from both scrubbed flues. Requirement M9 is designed to elaborate on the SWCAA-only regulation, integrate its requirements with those from the RACT Order, and provide periodic assurance of compliance with the particulate matter exhaust concentration standards.

Past source testing at the bypass stacks has indicated compliance with the particulate matter emission limits by a wide margin. With one exception during a scrubber upset, source tests on scrubbed flues have demonstrated compliance with the PM emission limits by an adequate margin. Because continuous methods are used to quantify emissions of SO_2, NO_X, and CO, compliance with the PM emission limits has been repeatedly demonstrated by a wide margin, and because opacity monitor data utilized as part of a CAM plan, and equipment maintenance review provides additional assurance that PM emission limits are met, periodic source testing is adequate to provide a reasonable assurance of continuous compliance with the PM emission limit.

Ammonia slip monitoring must be conducted at least annually, and as frequently as semiannually in accordance with the requirements of the Second Revision of BART Order No. 6426. Between source emission tests, urea usage is monitored in accordance with M25. Large increases in urea usage without corresponding decreases in NO_X emissions would indicate the possibility of increased ammonia slip.

M9. Coal Plant Continuous Monitoring Provisions

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from SWCAA 400, the specific emission limits contained in SWCAA 97-2057R1, Second Revision of BART Order No. 6426, 40 CFR 63 Subpart UUUUU, and to provide compliance with the Acid Rain requirements.

CEMS for SO_2, NO_X, CO, CO_2, Hg, and moisture monitor exhaust concentrations and allow for the calculation of mass emission rates of these pollutants from the coal-fired boiler. A COMS for measuring the opacity of emissions has been retained at each bypass stack but will not be installed on the scrubber flues because condensed water vapor makes opacity monitoring at these flues impossible. Note that TransAlta received an official exemption from the Acid Rain Program COMS requirements for the scrubbed stacks in accordance with 40 CFR 75.14(b) [see letter from Sam Napolitano (EPA) to Lou Florence (TransAlta) dated July 28, 2011]. SWCAA 97-2057R1 requires the use of an SO_2/O_2 CEMS on the bypass stacks. NO_X and CO_2 CEMS are not required on the bypass stacks by SWCAA 97-2057R1, local, state, or federal (40 CFR 75) regulations. The CEMS and/or COMS are calibrated daily in the active stack to ensure accurate measurements. An O_2 monitor measures and records O_2 concentration in the stack gas discharged to the atmosphere consistent with the Acid Rain monitoring provisions, although the requirement for operating an O_2 monitor is based on SWCAA 97-2057R1, Sections 21 and 27a, and SWCAA 400-040(6) and 400-050(3) which specify that the 1-hour average SO_2 concentration data be on a dry basis corrected to 7% O_2. The correction method uses the as-measured SO_2 concentration for each clock hour and the corresponding actual O_2 concentration to standardize the SO_2 data to 7% O_2, as shown:

$$SO_2, \text{dry @ } 7\%\ O_2 = [(20.9 - 7) / (20.9 - O_2\%, \text{dry})] * SO_2, \text{dry @ actual } O_2\%$$

This monitoring is to be used for demonstrating compliance with the specific pollutant emissions limits and standards in the permit. The monitors are to be installed, operated, maintained, and calibrated in accordance with the Acid Rain Program monitoring requirements and Subpart UUUUU as applicable. SWCAA 400-040 does not directly establish any specific regime of continuous monitoring or recordkeeping for the COMS. Consequently, SWCAA has used the monitoring requirements from SWCAA 97-2057R1 Section 36 and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615. Requirement M9(c) is designed to assure compliance with the state visible emissions standard using the COMS 6-minute average opacity data. Monitoring of 1-minute average opacity also meets this monitoring requirement because 6-minute averages may be calculated from 1-minute average data. This method of evaluation is deemed adequate to demonstrate compliance with the visible emissions standard of SWCAA 400-040(1), which is primarily a visual observation method. SWCAA 97-2057R1 Section 36 specifies that evaluation of the visible emission standard occur by both COMS and visual observation using Method 9 as prescribed in Appendix A to the permit.

Missing data procedures for the Acid Rain Program are specified for those hours when the CEMS does not measure or record valid data for the applicable monitors. The requirements specify methods for substituting data depending on factors such as the length of the missing data period and monitor system data availability rate. For compliance with the SO_2 concentration standard of SWCAA 400-040(6), the missing data procedures are identical to

those of 40 CFR 75.30 - 75.33 when the length of the missing data period is four hours or less. However, when monitor out-of-service periods are greater than four hours, data from an on-line coal analyzer, any as-burned coal analyses conducted by the permittee, and plant operating data is evaluated. For state and local rules and permits, the purpose of missing data substitution is to represent true and actual emissions as closely as possible. Therefore, the data or combination of data that best represents actual emissions is used to determine the SO_2 concentrations.

Missing data substitution procedures of 40 CFR 75 are not utilized to demonstrate compliance with the NO_X emission limit from the Second Revision of BART Order No. 6426 or the SO_2, PM, or Hg emission limits from 40 CFR 63 Subpart UUUUU. Reported emissions for comparison with these limits are intended to be more representative of actual emissions than the more conservative reporting required by 40 CFR 75 (Acid Rain Program Monitoring).

Electric output monitoring was added under the "gap filling" provisions of WAC 173-401-615 in order to allow the calculation of SO_2, PM, and Hg emission rates in units of lb/MWh or lb/GWh for comparison with the emission limits in 40 CFR 63 Subpart UUUUU.

Section M9(s) describes the requirements to monitor the bypass stack for SO_2, Hg, and PM in accordance with 40 CFR 63.10006(c) and 40 CFR 63.10010(a)(4). 40 CFR 63.10010(a)(4) indicates that if a relevant CEMS is not installed on the bypass stack, bypass hours are counted as deviations from the monitoring requirements. Based on a review of EPA's December 2011 Response to Public Comments, it appears that EPA intends to count a failure to monitor the bypass stack for either Hg or PM as a deviation from Subpart UUUUU requirements only if the bypass stack is used outside of startup or shutdown. Otherwise is appears that EPA would simply count unmonitored bypass hours as monitor downtime. In EPA's response to Commenter 17675, EPA writes:

"... The EPA has modified the bypass stack monitoring requirements. Under 40 CFR Part 75, the EPA allows the use of a maximum potential concentration value on a bypass stack. That approach works within the broad context of an emissions trading program but does not work when evaluating compliance with a specific emission limit over a shorter period. Thus, the final rule provides two other options for a source. One is to monitor the bypass stack consistent with the proposed rule. The other is to treat any hours of bypass stack emissions as periods of monitor downtime. In general, this is consistent with the EPA's approach to startup and shutdown periods, in that we treat those periods as subject to a work practice standard. That generally obviates the need to monitor the bypass stack as the emission limit does not apply during the periods when the source is most likely to operate a bypass stack..."

In the past many facilities, although not this facility, have operated certain pollution control equipment only seasonally, therefore the bypass stack was routinely used during normal operation. The requirement in Subpart UUUUU to monitor the bypass stack addresses this possibility.

M10. 40 CFR 63 Subpart UUUUU Recordkeeping and Startup Monitoring

This recordkeeping requirement is taken directly from 40 CFR 63 Subpart UUUUU and the general requirements of 40 CFR 63.8 and 40 CFR 63.10 that apply to Subpart UUUUU

M11. Coal Plant Startup, Shut Down, and Outage Operation Procedures for RACT Order

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the specific requirements contained in SWCAA 97-2057R1. Pursuant to SWCAA 400-081 "Start-up and Shutdown," technology based emission standards and control technology determinations must take into consideration the physical and operational ability of a source to comply with the applicable standards during start-up or shutdown. Where it is determined that a source is not capable of achieving continuous compliance with an emission standard during start-up or shutdown, SWCAA must include appropriate emission limitations, operating parameters, or other criteria to regulate performance of the source during start-up or shutdown.

M9 ensures sufficient monitoring to excuse unavoidable excess emissions or demonstrate compliance with the permit. The use of terms, test methods, units, averaging periods, and other conventions will be consistent with the applicable requirements. Emissions control equipment is operated to minimize overall emissions, except to the extent equipment operation will cause degradation of its long-term performance.

Exceedances of the PM and opacity limitations are excused under SWCAA 97-2057R1 based on SWCAA 400-107 during on-line preventive maintenance and manual ESP rapping which may cause short duration emissions increases, and during startup and shutdown when the ESPs are out of service. Excess emissions due to scheduled maintenance are considered unavoidable if the permittee adequately demonstrates the excess emissions could not have been avoided through reasonable design, better scheduling for maintenance, or through better operation and maintenance practices. ESP component maintenance and manual rapping of ESP plates are among the maintenance activities that often result in short duration excess emissions, however these excess emissions are considered unavoidable and necessary to enhance long-term equipment performance and, as such, are excused from penalty.

Shutdown of one FGD system requires opening of the damper to the associated bypass stack. This operation has been known to cause excess opacity. The cause of the excess opacity is believed to be re-entrainment of ash deposited in the duct near the damper. Excess opacity due to opening of the bypass damper and re-entrainment of ash deposits is unavoidable, and therefore will be excused from penalty providing:

(a) The permittee reports the excess emission as soon as possible but no later than 48 hours after discovery;

(b) The permittee adequately demonstrates that the cause of the excess opacity was opening of the bypass duct (e.g. the excess opacity was contemporaneous with bypass duct opening); and

(c) The permittee adequately demonstrates that directing flue gas to the bypass stack was unavoidable (e.g. the FGD shutdown was not reasonably preventable).

Hourly SO_2 emissions during shutdown, startup, and maintenance of the SO_2 emission control technology in excess of 250 ppm are excused under SWCAA 400-107 provided the alternative hourly SO_2 limits of Req-20 are not exceeded. Shutdown and startup periods are defined based on an ESP temperature of 220°F or below, and the startup period begins when fuel is

introduced into a boiler to raise its temperature to operating conditions. ESP operation during startup and shutdown of EU-1 or EU-2 will degrade the overall ESP performance. When ESP temperature is below about 220°F, and especially when the boiler is combusting fuel oil, continued operation can result in fouling of the precipitator plates, which decreases long-term PM collection efficiency. Operation of the SO_2 emission control technology when the ESPs are off line and not removing PM is expected to foul or possibly plug key components, so the SO_2 emission control technology is not required to be placed in operation until the upstream ESPs are functioning. The end of the startup period is defined based on identifiable operating events.

Emissions in excess of both the 250 ppm hourly SO_2 limit and the alternative shutdown, startup, and SO_2 emission control technology outage limits of Req-20 may be excused provided the permittee meets the burden of proof regarding unavoidable emissions under SWCAA 400-107, especially subsections (4), (5), and (6). For unit startups, shutdowns, and on-line maintenance when the SO_2 emission control technology is out of service, the permittee is expected to blend lower sulfur coal into the boiler fuel supply prior to a planned outage of the SO_2 control system. The permittee submitted a scrubber startup, shutdown, and maintenance procedure in correspondence dated September 19, 2002. The document outlines the procedures implemented by the permittee to maintain compliance with the emission limits and operational requirements imposed by applicable air regulations and permits.

If burning high sulfur coal, sulfur dioxide emissions in excess of the 1,000 ppm limit in Req-19 are unavoidable during the first 6 – 8 hours (the length of time required to burn through coal stored in the silos) of a forced outage of the flue gas desulfurization (FGD) system if the cause of the forced outage is itself unavoidable. Good air pollution control practice for minimizing emissions during a forced outage of the FGD system include changing the coal blend so that emissions will be reduced below the 1,000 ppm limit after the high-sulfur coal blend is burned out of the silos. The permittee has indicated that the coal blend will be changed within approximately 15 minutes of notification of a scrubber problem.

M12. Coal Plant SO_2 12-Month Period Emission Evaluation

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the specific requirements contained in SWCAA 97-2057R1. Calculation of the annual tons of SO_2 emitted for comparison with the limitations must include all hourly SO_2 emission data, including startups, shutdowns, upsets, and forced or planned emission control system outages. An exceedance of the annual limitation is defined as any consecutive 12 calendar months in which SO_2 emissions exceed the tons per year SO_2 limitations applicable at the time. Although each day in the last month of the 12-month exceedance period can be treated as a separate day of violation, an alternative day-by-day evaluation method can be used by the permittee to more specifically identify the violation period. According to the alternative evaluation method, the number of violation days is equal to the number of 365-day emission summations, ending within the last month of the exceedance period, in which the SO_2 emissions exceed the annual limitation. This alternative evaluation method is the same as a 365-day rolling total, rolled each calendar day.

M13. Coal Plant SO_2 Monitoring of Bypass Stacks

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the specific requirements contained in SWCAA 97-2057R1. The owners of the Centralia Plant had sole discretion to select the SO_2 and NO_X emission control technologies provided they met the applicable emission limits. The control technology configuration could include the maintenance of the original stacks for bypass provided a CEMS was maintained to monitor SO_2 emissions from the bypass stacks.

If the bypass stacks do not contain certified functional CEMS for SO_2, any emergency bypass emissions released through these stacks will be considered an upset condition reportable to SWCAA as a deviation from permit conditions. All SO_2 emissions released from the facility, regardless of where, how, or under what operating condition, is included in the plant SO_2 total for comparison with the annual limitation.

M14. Coal Plant Fuel Oil Usage Evaluation

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the specific requirements contained in SWCAA 97-2057R1 and the fuel usage monitoring requirement of 40 CFR 63.7525(k). The permittee is required to monitor fuel oil usage in all of the boilers. The permittee accepted a voluntary limit on the amount of fuel oil consumed by the auxiliary boiler (EU-3) so it would not be necessary to evaluate RACT for this unit. RACT may have otherwise been applicable because the auxiliary boiler's potential-to-emit was sufficient to qualify it as a major source on its own, even though emissions calculated from actual fuel usage resulted in emissions substantially below the major source threshold. To evaluate fuel usage compared to the consumption limit, the auxiliary boiler must be equipped with a separate fuel meter or be supplied by its own unique fuel tank to identify fuel consumed in the auxiliary boiler. If the auxiliary boiler consumes fuel oil containing the maximum allowed 0.5% sulfur by weight, the SO_2 emissions from EU-3 will be larger than emissions of other criteria pollutants from EU-3. Emissions are calculated based on emission factors from U.S. EPA AP-42 §1.3. An example of this SO_2 emission calculation using the maximum allowed annual fuel consumption is shown below:

$$\frac{600{,}000\ \text{gallons}}{\text{year}} \bullet \frac{7.206\ \text{lb oil}}{\text{gallon}} \bullet \frac{0.005\ \text{lb S}}{\text{lb oil}} \bullet \frac{1\ \text{lb}\cdot\text{mole S}}{32\ \text{lb S}} \bullet \frac{64\ \text{lbs SO}_2}{\text{lb}\cdot\text{mole SO}_2} \bullet \frac{1\ \text{ton}}{2{,}000\ \text{lbs}} = 21.6\ \text{tons per year}$$

The daily fuel monitoring requirement of 40 CFR 63.7525(k) is used to demonstrate that the boiler remains in the "limited use" subcategory and is exempt from many of the requirements of 40 CFR 63 Subpart DDDDD.

M15. Black Stop Diesel Generator Engine Source Testing Requirements

Requirements removed – the Black Stop Generator Engine was permanently retired at the end of 2020.

M16. Black Stop Diesel Generator Engine Startup and Shutdown

Requirements removed – the Black Stop Generator Engine was permanently retired at the end of 2020.

M17. Black Stop Diesel Generator Engine Fuel Certification

Requirements removed – the Black Stop Generator Engine was permanently retired at the end of 2020.

M18. Black Stop Diesel Generator Engine Hours Monitoring

Requirements removed – the Black Stop Generator Engine was permanently retired at the end of 2020.

M19. Maintenance Activities Monitoring

The data provided by this monitoring requirement, in conjunction with source testing, provides a reasonable assurance that emissions that are not monitored continuously are within permitted limits. Each occurrence of maintenance and repairs to the fly ash unloading pugmill or turbine lube oil mist eliminators that may affect emissions is recorded. This data is available to plant personnel and SWCAA upon inspection. This data can be periodically reviewed by SWCAA and plant personnel to determine if emission factors used to calculate emissions remain valid.

For example, the replacement of filters in the lube oil mist eliminators could affect emissions if a slightly different filter were installed, therefore filter replacements for the turbine lube oil mist eliminators must be documented.

his monitoring term was included in SWCAA 01-2403 because it can be a valuable inspection tool that requires minimal effort on the part of the permittee.

M20. Particulate Matter Compliance Assurance Monitoring for BW22

The permittee was required to submit a Compliance Assurance Monitoring (CAM) plan for particulate matter emissions from EU-2 in accordance with 40 CFR 64 for the permit renewal in 2004. CAM is applicable to emissions from both the bypass and FGD stacks of EU-2. The permittee's CAM plan was approved as incorporated into the Air Operating Permit. The CAM plan utilizes opacity as a surrogate indicator of particulate matter control device operation and particulate matter emissions.

The CAM plan for the bypass stacks was required because the permittee is allowed to use the bypass stack for limited periods of time outside of startup, shutdown, and extreme emergency conditions. To date, the bypass stacks have not been used except during startup, shutdown, and upsets. Because facilitywide SO_2 emissions are limited to 10,000 tons per year, use of the unscrubbed bypass stack rapidly utilizes the allowable annual emissions (at a rate of ~5 tons per hour), therefore use of these stacks outside of startup, shutdown, and extreme emergencies is unlikely. Any significant use of the bypass stack can result in

restrictions on plant operation to maintain compliance with the 10,000 ton per year SO_2 limit.

For the FGD stack, opacity in the ductwork upstream of the scrubber of less than 30% provides an adequate assurance that particulate matter emissions from the applicable FGD stack will be less than the permit limit. Source testing at this facility has demonstrated that the scrubber is highly efficient at removing particulate matter from the flue gas. Particulate matter emission levels well below the indicator range will adversely affect scrubbing liquor chemistry and gypsum quality and potentially result in damage to the scrubber, therefore the permittee is highly motivated to maintain opacity levels well below the 30% level.

When an excursion occurs, the Permittee is required to suhmit a report that includes the "ESP field settings" along with the fields out of service. The ESP field settings are the secondary voltage and secondary current, consistent with 40 CFR 63 Subpart UUUUU.

M21. Coal Unloading Facility

The data provided by this monitoring requirement is used to calculate annual emissions of particulate matter from the coal unloading facility.

M22. FGD Bleed Treatment Lime Storage Silo

Differential pressure across the dust collector must be recorded at least monthly to assist in evaluating whether the dust collector is operating properly. Large changes in differential pressure can indicate operational problems. The number of hours the silo is actively vented must be recorded annually to allow the calculation of emissions from the silo. In conjunction with the monthly inspections required by M3, this data will provide a reasonable assurance of ongoing compliance with the particulate matter emission limits.

M23. Journal Shop

The amount of each type of welding rod that is used in the Journal Shop must be monitored and recorded to calculate annual emissions. The Journal Shop baghouse is designed to provide a high level of control and utilizes both primary filters and secondary HEPA filters. SWCAA believes that unless there is an obvious upset condition (for which monitoring is required), the unit will comply with particulate matter emission limits.

M24. Reserved

M25. SNCR System Monitoring

In accordance with Condition 4 of the Second Revision of BART Order No. 6426, ammonia monitoring is required only when urea injection exceeding 1.5 gallons per minute is used for NO_X control. Condition 7 requires reporting of the urea concentration and injection rate within 30 days of first injecting urea in a calendar year, but does not include monitoring, or any reporting after those 30 days. Urea flow rate monitoring is necessary for SWCAA and Ecology to know when ammonia testing is required; therefore, this

provision was added under the "gap filling" monitoring provisions of WAC 173-401-615(1).

M26. Coal Plant Emergency Engine Monitoring

These requirements come directly from 40 CFR 60 Subpart IIII (for Emergency Diesel Generator 2), 40 CFR 63 Subpart ZZZZ (for Emergency Diesel Generator 1), and SWCAA 16-3188. For the purposes of Subparts IIII and ZZZZ, the engines are classified as emergency compression ignition engines with a site rating of less than 500 horsepower. For this classification of engine in each rule, the applicable requirements are all operating or maintenance requirements. The permittee must document how many hours each engine is operated, and for what purpose it was operated, to demonstrate that the engines are indeed being operated as emergency engines. Because all operating and maintenance activities must be documented, and all operating hours accounted for, these monitoring provisions provide a reasonable assurance of compliance with the applicable requirements. A review of the documentation for a specific engine will conclusively determine the compliance status of the unit with respect to the operating and maintenance requirements.

M27. Fire Pump Engine Monitoring

M27(a) comes directly from SWCAA 16-3188 and provides a reasonable assurance of compliance with the fuel sulfur limitations and allows for the calculation of annual sulfur dioxide emissions.

M27(b) comes directly from SWCAA 16-3188 and provides a reasonable assurance of compliance with the hours limitation and allows for a calculation of annual emissions.

Unless new testing is conducted after the issuance date of SWCAA 16-3188 (June 1, 2016), the following emission factors are to be used:

Pollutant	**Fire Pump Engine Emission Factors (lb/hr)**
NO_X	1.12
CO	0.54
PM	0.050
PM_{10}	0.050
$PM_{2.5}$	0.050

M27(c) provides a reasonable assurance of compliance with the maintenance requirements of 40 CFR 63 Subpart IIII. Subpart IIII requires that certain maintenance activities be undertaken as specified frequencies (measured in the number of hours an engine has operated) but does not include any provision for monitoring how many hours an engine has operated. SWCAA has required the permittee to document the hour meter reading at each incident of maintenance and repairs under the "gap filling" provisions of WAC 173-401-615. Since maintenance activities must occur at least once per year, this means that at least once per year there will be written documentation of the number of hours of operation between maintenance events. Also, at any time after the first maintenance event, the

permittee or the inspector can compare the hour meter reading for an engine to the hour meter reading during the last maintenance event to determine whether the maintenance schedule is being met.

M28. Coal Unloading Facility Emergency Diesel Sump Pump Engine Monitoring

M28(a) comes directly from SWCAA 11-2972 and provides a reasonable assurance of compliance with the fuel sulfur limitations and allows for the calculation of annual sulfur dioxide emissions.

M28(b) comes directly from SWCAA 11-2972 and provides a reasonable assurance of compliance with the hours limitation and allows for a calculation of annual emissions.

Unless new testing is conducted after the issuance date of SWCAA 11-2972 (April 14, 2011), the following emission factors are to be used:

Pollutant	Emission Factors (lb/hr)
NO_X	2.54
CO	0.44
PM	0.055
PM_{10}	0.055
$PM_{2.5}$	0.055

M28(c) provides a reasonable assurance of compliance with the maintenance requirements of 40 CFR 60 Subpart IIII. Subpart IIII requires that certain maintenance activities be undertaken as specified frequencies (measured in the number of hours an engine has operated) but does not include any provision for monitoring how many hours an engine has operated. SWCAA has required the permittee to document the hour meter reading at each incident of maintenance and repairs under the "gap filling" provisions of WAC 173-401-615. Since maintenance activities must occur at least once per year, this means that at least once per year there will be written documentation of the number of hours of operation between maintenance events. Also, at any time after the first maintenance event, the permittee or the inspector can compare the hour meter reading for an engine to the hour meter reading during the last maintenance event to determine whether the maintenance schedule is being met.

This documentation can be compared with the written maintenance instructions provided or approved by the manufacturer to determine the status of compliance with this requirement.

M29. Mercury Control System and Fly Ash Material Handling

The number of hours each unit is operated must be logged to allow for the calculation of annual emissions. Annual emissions must be calculated using the emission factors shown below unless new emission factors are developed through source testing.

Filter	(lb/hr)
SEA System 1	0.048
SEA System 2	0.048
Sorbent Silo 1	0.015
Sorbent Silo 2	0.015
Fly Ash Bin 11	0.63
Fly Ash Bin 12	0.63
Fly Ash Bin 14	0.63
Fly Ash Bin 14 Air Slide to Bin 11 Air Slide	0.039
Fly Ash Bin 11 to Weigh Hopper Air Slide	0.039
Fly Ash Bin 14 to 6050 Air Slide	0.026

The above emission rates listed in the table above are based on the design flow rate for each unit and the permitted emission concentration (0.005 gr/dscf).

M30. Fly Ash Baghouses - Source Emission Testing Requirements

Initially, periodic source emissions testing was coupled with the use of a baghouse leak detection system to provide a reasonable assurance with the permitted emission limits. This was the same approach taken by EPA in NSPS and MACT standards (e.g. NSPS Subpart Y) issued after November 15, 1990 to assure compliance with numeric particulate matter limits; therefore, this approach was presumed to be equivalent to CAM. A CAM Plan was later developed for these baghouses in accordance with 40 CFR 64 and is included as M34. The CAM Plan replaced the previous requirement to operate the baghouse leak detectors in accordance with the requirements in 40 CFR 62.256(c).

The initial alarm setpoints of 100 pA were established based on the results of source emissions testing conducted October 2011 during which the following results were obtained:

Baghouse	Bin 11	Bin 12	Bin 14
Filterable PM	0.0001 gr/dscf	0.0002 gr/dscf	0.0001 gr/dscf
Leak Detector Output	23 pA	18 pA	42 pA

The system utilizes a Tribo-Flow model 4001-1111-0I-154N detector. Manufacturer literature indicates that the equipment is designed for a detection limit on the order of 0.0005 gr/dscf; therefore, the instrument response during the initial testing appears to be a low baseline. The 100 pA alarm setpoint is significantly less than 10 times this baseline for all stacks and well below the response expected at a concentration of 0.005 gr/dscf (the permit limit).

M31. Fly Ash Bin Baghouses – Compliance Assurance Monitoring

The permittee was required to submit a Compliance Assurance Monitoring (CAM) plan for particulate matter emissions from EU-17, EU-18, and EU-19 in accordance with 40 CFR 64 for the permit renewal in 2014. CAM is applicable to these units because

uncontrolled PM emissions would be expected to exceed 100 tons per year each. The permittee's CAM plan was approved as incorporated into the Air Operating Permit. The CAM plan utilizes an electrostatic particle detection system (also known as a baghouse leak detection system) as a surrogate indicator of particulate matter control device operation and particulate matter emissions. This is the same approach taken by EPA in NSPS and MACT standards (e.g. NSPS Subpart Y) issued after November 15, 1990 to assure compliance with numeric particulate matter limits; therefore, this approach is presumed to satisfy CAM requirements.

During initial source emissions testing in October 2011, emissions from the baghouses were measured at 0.0001 – 0.0002 gr/dscf. This level is generally at the method detection limit and 25-50 times lower than the applicable emission limit of 0.005 gr/dscf. During the testing the electrostatic particle detector readings were 18 – 42 pA. Based on this testing, TransAlta's initial alarm setpoint of 100 pA was sufficiently protective of the permit limit that no additional testing was necessary to establish an appropriate upper limit to the indicator range.

Alarm setpoints for these types of detectors may need to be adjusted from time to time due to changes in stack conditions, ambient conditions, or detector replacements. Where such detectors are referenced in NSPS/MACT regulations (e.g. 40 CFR 60 Subpart Y, 40 CFR 63 Subpart SSSSSS), sources are allowed to change the alarm setpoints quarterly in accordance with their site-specific monitoring plan. TransAlta's CAM plan (analogous to a site specific monitoring plan under NSPS/MACT regulations) indicates that changes to the alarm setpoint would be based upon the results of source emissions testing. SWCAA incorporated this provision into the Permit.

M32. Reserved

M33. Coal-Fired Boiler Tune-up and Startup/Shutdown Monitoring

40 CFR 63 Subpart UUUUU requires periodic tune-ups in accordance with specific requirements. In addition, all "applicable control technologies" must be engaged when firing anything other than "clean fuels". In this case, the only other fuel is coal.

A semiannual compliance report must be submitted that includes the date of the most recent tune-up and a report if there were any deviations from the work practice standards (consisting of the tune-up and the startup and shutdown provision). 40 CFR 63.10032(a)(1) requires sources to maintain all documentation supporting each semiannual report. This requirement describes this documentation as it pertains to the work practice standards (tune-ups and startup/shutdown provisions).

Full documentation of each tune-up as required by section (a) provides all of the records necessary to determine if all the tune-up requirements are being met.

The information in section (b) is necessary to determine:

a. That "clean fuels" are being burned during startup;
b. When the unit is in startup or shutdown, because the emission limits from Subpart UUUUU do not apply during startup or shutdown; and

c. That the relevant emission control equipment is being engaged when required.

M34. Auxiliary Boiler Tune-up Monitoring

40 CFR 63 Subpart DDDDD requires periodic tune-ups in accordance with specific requirements. The initial tune-up must be fully documented in to comply with 40 CFR 63.7555(a)(1), but there is no specific requirement to fully document subsequent tune-ups. Consequently, SWCAA has implemented this documentation requirement for subsequent tune-ups under the "gap filling" provisions of WAC 173-401-615.

Full documentation of each tune-up as required by this requirement provides all of the records necessary to determine if all the tune-up requirements are being met.

M35. Fine Coal Handling

The requirements listed this monitoring condition are all included in both 40 CFR 60 Subpart Y and SWCAA 14-3093. Because the permittee has not committed to a single monitoring strategy, both of the allowable strategies were included. The total amount of coal transferred is required by Subpart Y and necessary to calculate annual emissions.

M36. Acid Rain, RACT, and NSR CEMS Data Recordkeeping Requirements

This recordkeeping section is taken from 40 CFR 75.57, 75.58, and 75.59 and supplemented by specific requirements from SWCAA 97-2057R1, and the "gap filling" provisions of WAC 173-401-615(2).

The Acid Rain Program requires that pertinent records be maintained for at least three years from the date of the record. However, the recordkeeping provisions of the Air Operating Permit regulations, WAC 173-401-615(2)(c), require retention of records for a period of five years.

The basis for recordkeeping requirements for 1-hour SO_2 standard concentrations (dry @ 7% O_2) is the "gap filling" provisions of WAC 173-401-615(2). Data from the plant computer system not required by the Acid Rain Program is not saved for archiving in the same way that data consistent with 40 CFR 75.57 - 75.59 is recorded.

The Acid Rain regulation specifies the type and format of data to be recorded for flow and SO_2 emissions from Acid Rain affected units. The data recordkeeping requirements pursuant to SWCAA 97-2057R1 for 1-hour SO_2 standard concentration (dry @ 7% O_2) are parallel to those of the Acid Rain Program, but for a smaller quantity of required data. The data recordkeeping requirements for rolling 12-month SO_2 emissions (tons per year) are specified, and the additional data to be included in this summation stated for recordkeeping purposes.

The data recordkeeping requirements for hourly NO_X corresponding to unit generating load of 360 MW gross or greater are parallel to those of the Acid Rain Program, but for a smaller quantity of required data pursuant to SWCAA 97-2057R1 Section 30.

M37. 40 CFR 63 Subpart DDDDD Recordkeeping

This recordkeeping requirement is taken directly from 40 CFR 63.7555 and 40 CFR 63.7560.

M38. 40 CFR 60 Subpart Y Recordkeeping

This recordkeeping requirement is taken directly from 40 CFR 60 Subpart Y. The amount of coal processed will be the amount of coal conveyed to the permittee's facility and used to calculate annual emissions.

VIII. EXPLANATION OF SELECTED REPORTING TERMS AND CONDITIONS

R1. Deviations from Permit Conditions and CAM Excursions

The permittee is required to report all permit deviations promptly. This reporting requirement is taken directly from WAC 173-401-615(3) and is included in some form in PSD-01-01 Amendment 2 Condition 22(d)(1), Second Revision of BART Order No. 6426 Section 11,SWCAA 97-2057R1 Sections 23, 28, 29, and 37, SWCAA 01-2403 Section 11(e)(1), SWCAA 01-2350R4 Conditions 28(a & b), SWCAA 11-2984 Conditions 15 and 16, SWCAA 14-3093 Conditions 17 and 18, and SWCAA 16-3188 Conditions 12 and 13. SWCAA defines "prompt" in the permit in relation to the degree and type of deviation likely to occur and the applicable requirement. Excess emissions of SO_2, particulate matter, or opacity are to be reported to SWCAA during the current business day or next business morning. A written report may be requested by SWCAA and is required for any SO_2 emission control technology forced outage longer than 72 hours. Any emissions released through a bypass duct without a certified functioning CEMS are defined as an upset condition which must be reported to SWCAA during the current business day or by the next business morning and must be documented to SWCAA within 5 days of occurrence. All other deviations must be reported no later than 30 days following the end of the month during which the deviation was discovered. This reporting frequency is taken from WAC 173-401-615(3).

R2. Complaint Reports

The permittee is required to report all complaints to SWCAA within three business days of receipt to ensure prompt complaint response. This reporting section is based on WAC 173-401-615(3), and SWCAA's definition of "prompt" for reporting of complaints.

R3. Quarterly Reports

The permittee is required to report specific monitoring records and provide a certification of monitoring records on a quarterly basis for the Acid Rain Program. Although a semiannual report on the status of, and certification of monitoring records is required by WAC 173-401-615(3), quarterly reporting of specified monitoring records is required under 40 CFR 75.64, with compliance certification according to 40 CFR 75.64(c). Non-Acid Rain reporting requirements for the coal plant are derived from 40 CFR 63 Subpart UUUUU, the Second Revision of BART Order No. 6426, SWCAA 97-2057R1 Sections 27d, 43, and 45, and WAC 173-401-615(3). Non-Acid Rain reporting requirement for the combustion turbine facility

are specified in SWCAA 01-2350R4 and PSD-01-01 Amendment 2. Although records are reported quarterly, certification of non-Acid Rain monitoring records is only required every six months consistent with WAC 173-401-615(3).

No specific NO_X reporting requirements were included in the SWCAA 97-2057R1 to demonstrate compliance with the NO_X emission limits that apply at 360 MW or greater, therefore section R3(e) was added using the "gap-filling" provisions of WAC 173-401-615.

For Subpart UUUUU reports, no special SO_2 CEMS data reporting are listed because reporting of SO_2 data (and supporting diluent and/or moisture monitors) is covered by the Acid Rain Program reporting requirements (see the Acid Rain Permit and 40 CFR 75). EPA guidance indicates that Acid Rain Program requirements must not be detailed in Title V permits. The Acid Rain Permit incorporates the appropriate requirements by reference. The Hg CEMS reporting requirements mirror the Acid Rain Program reporting requirements for SO_2 and require utilization of the same data reporting system. SWCAA will have access to the data through EPA's system upon submission.

R4. Semiannual Reports

The permittee is required to provide a report of all monitoring records and provide a certification of all reports on a semi-annual basis. Semiannual reporting and certification of monitoring records is required by WAC 173-401-615(3). A Responsible Official must certify all reports required by the Title V permit.

In addition, specific reporting elements required by 40 CFR 63 Subpart UUUUU have been listed.

R5. Annual Reports and Compliance Certification

The permittee is required to report and certify compliance with all permit terms and conditions on an annual basis. Annual compliance certification is required by WAC 173-401-630(5) for all requirements, including Acid Rain Program requirements. Since 2005, a separate Acid Rain Program certification has not been required.

All of the items other than the compliance certification are used to calculate annual emissions from individual emission units.

R6. Emission Inventory Reports

The permittee is required to report an inventory of emissions from the source on an annual basis. Annual reporting of emissions inventory is required under SWCAA 400-105 to be submitted to SWCAA by March 15th for the previous calendar year unless an extension is approved by SWCAA. SWCAA's Executive Director may extend the submittal date to April 15th (the deadline in WAC 173-400-105).

R7. Source Test Plans and Reports

The permittee is required to notify SWCAA in advance of all required source testing so that SWCAA personnel may be present during testing. The permittee must also report test results within 45 days of test completion to allow timely review by SWCAA. Operating conditions are also to be included in all test reports to relate emissions to the method of operation. Source testing described in monitoring requirements M8 and M15 are examples of source test results subject to this reporting requirement.

R8. Acid Rain Notification of Certification and Recertification Test Dates and Applications and Other General Reporting Provisions

This reporting section is taken from 40 CFR 75.60, 75.61 and 75.63 to indicate that the reporting requirements in these Acid Rain sections apply. Advance notification within specified time periods is required for the date each unit commences commercial operation, CEMS certification and recertification tests, relative accuracy test audits, and COMS certification and recertification tests at Acid Rain affected units. An application for certification or recertification is required for Acid Rain affected units. Each certification application is to be submitted in electronic or paper format as specified by the EPA Administrator. The permittee must comply with All Acid Rain reporting requirements in 40 CFR 75.60.

R9. BART Order Milestone and Urea Injection Reports

This reporting section is taken directly from the Second Revision of BART Order No. 6426.

R10. 40 CFR 63 Subpart DDDDD Reports for Auxiliary Boiler

This reporting section is taken from 40 CFR 63.7545(e) and 40 CFR 63.9. The Notification of Compliance Status must include an identification of which category each boiler is in for the purposes of 40 CFR 63 Subpart DDDDD. The Auxiliary Boiler (EU-3) is in the "Limited Use Boiler" subcategory.

R11. 40 CFR 63 Subpart UUUUU Reports

This reporting section is taken from 40 CFR 63 Subpart UUUUU and includes all reports not required to be submitted each quarter or semiannually.

R12. 40 CFR 60 Subpart Y Performance Monitoring Reports

This reporting section is taken from 40 CFR 63 Subpart Y and applies to the periodic visible emission evaluation reports required by Subpart Y.

IX. COMPLIANCE HISTORY

The following Notices of Violation (NOV) were issued for the time period beginning 5 years before the current permit term.

NOC/ NOV No.	Violation Date	Notes
5881	7/12/2015	Bypass of the Unit 2 scrubber during normal operation. The bypass occurred because maintenance personnel accidentally locked out the pH probe signals, rather than the level probe signals, when performing a monthly preventative maintenance flush on the level probes
5882	7/23/2015	Failure to complete SNCR optimization testing by the end of calendar year 2014.
6111	6/18/2016	Partial bypass of Unit 1 scrubber and associated opacity exceedance. The Unit 1 scrubber was partially bypassed between 11:20 and 11:48 on Saturday June 18, 2016. The partial bypass occurred when the connection between a damper actuator and control motor broke during a startup of Unit 1.
6121	8/22/2017	Unit 2 selective non-catalytic reduction (SNCR) system was offline between 05:52 and 11:28 when the urea tank ran empty. TransAlta's report of the incident indicated that they were maintaining a low level in the tank after some foundation concern following an earlier subsurface water leak. Subsequently the urea need increased due to increased operations and urea deliveries were not increased to compensate.
6123	7/28/2017, 8/3/2017, 10/9/2017	Exceedances of voluntary SO_2 emission limit established to protect NAAQS. Primary cause may have been that increasing emissions were not noticed in time by control room operators.
6125	8/5/2017 – 9/14/2017 U1 7/21/2017 – 9/13/2017 U2	Exceedances of the 30-boiler operating day rolling average mercury emission limit. Caused in part by under-feeding carbon adsorbent.
6426	2017	Improper operation of SNCR systems for Units 1 and 2 for calendar year 2017. Included under-injection of urea, use of incorrect injection devices, and use of incorrect urea concentrations.
6427	12/27/2017 – 1/23/2018	The mercury emissions from Unit 2 exceeded 1.2 lb/TBtu (30-boiler operating day rolling average) from December 27, 2017 through January 23, 2018.
10101	8/3/2018 – 8/10/2018	The mercury emissions from Unit 1 exceeded 1.2 lb/TBtu (30-boiler operating day rolling average) from August 3, 2018 through August 10, 2018.
10102	9/1/2018	Unit 1 scrubber bypass between approximately 05:25 and 06:01. The bypass was initiated by an inadvertent mouse click that resulted in one of the two ducts (duct 11) being placed in bypass mode.

NOC/ NOV No.	Violation Date	Notes
10103	11/8/2018	During the startup of Unit 1 on November 8, 2018 the selective non-catalytic reduction (SNCR) system was not engaged as early as it should have been to control NO_X emissions. During this startup a set of fans on the boiler tripped, which also tripped the SNCR system offline. The fact that the SNCR system had been tripped offline was not noticed by the operators until the shift change at 7:00 a.m. TransAlta reported that based on the steam flow the SNCR system should have been operational between 05:00 and 06:00. Operators noticed the issue and started the SNCR system between 07:00 and 08:00.
10106	1/1/2018 – 4/13/2019	Improper operation of the SNCR systems on both Units 1 and 2.

X. APPENDICES

Appendix A of the Air Operating Permit contains the methods by which visible emissions from the permittee's operations are to be evaluated when performing required monitoring. SWCAA has exercised its latitude under SWCAA 400-105(4) "Source Testing" to approve an alternative test method in advance for visible emissions. Approval has been granted via signature of SWCAA's Control Officer in this permit. The federal requirements still require that EPA Method 9 be performed. The difference between the Appendix A visible emission method and EPA Method 9 is the data reduction method used.

Appendix B of the Air Operating Permit contains the Acid Rain Permit for the Centralia Plant. The Acid Rain permit is effective beginning on the same date as this Air Operating Permit through the expiration date of this Air Operating Permit. Nearly all requirements in the Acid Rain permit are incorporated by reference to the applicable regulation; therefore changes in the applicable regulation are automatically incorporated into the permit.

Appendix C of the Air Operating Permit contains TransAlta's Small Engine Maintenance Plan used to meet the maintenance requirements of 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ for specific engines.

XI. PERMIT ACTIONS

Air Operating Permit SW98-8 (original Title 5 permit)

1. Final Permit Issued: August 6, 1999

Air Operating Permit SW98-8-R1 (administrative permit amendment)

1. Final Permit Issued: July 12, 2000

Air Operating Permit SW98-8-R2 (first renewal)

1. Final Permit Issued: August 6, 2004

Air Operating Permit SW98-8-R2-A (modification)

1.	Final Permit Issued:	May 12, 2005

Air Operating Permit SW98-8-R2-B (modification)

1.	Final Permit Issued:	March 25, 2008

Air Operating Permit SW98-8-R3 (second renewal)

1.	Renewal Permit Application Submitted:	February 3, 2009
2.	Permit Application Deemed Complete:	March 17, 2009
3.	Permit Application Sent to EPA:	May 15, 2009
4.	Draft Permit Issued:	May 15, 2009
5.	Proposed Permit Issued:	July 21, 2009
6.	Final Permit Issued:	September 16, 2009

Air Operating Permit SW98-8-R3-A (modification)

1.	"Reopening for Cause" Letter to Permittee:	July 12, 2011
2.	Draft Permit Issued:	September 14, 2011
3.	Proposed Permit Issued:	October 26, 2011
4.	Final Permit Issued:	December 21, 2011

Air Operating Permit SW98-8-R4 (third renewal)

1.	Renewal Permit Application Submitted:	September 16, 2013
2.	Permit Application Deemed Complete:	January 8, 2014
3.	Permit Application Sent to EPA:	January 8, 2014
4.	Draft Permit Issued:	June 6, 2014
5.	Proposed Permit Issued:	July 16, 2014
6.	Final Permit Issued:	September 16, 2014

Air Operating Permit SW98-8-R4-A (modification)

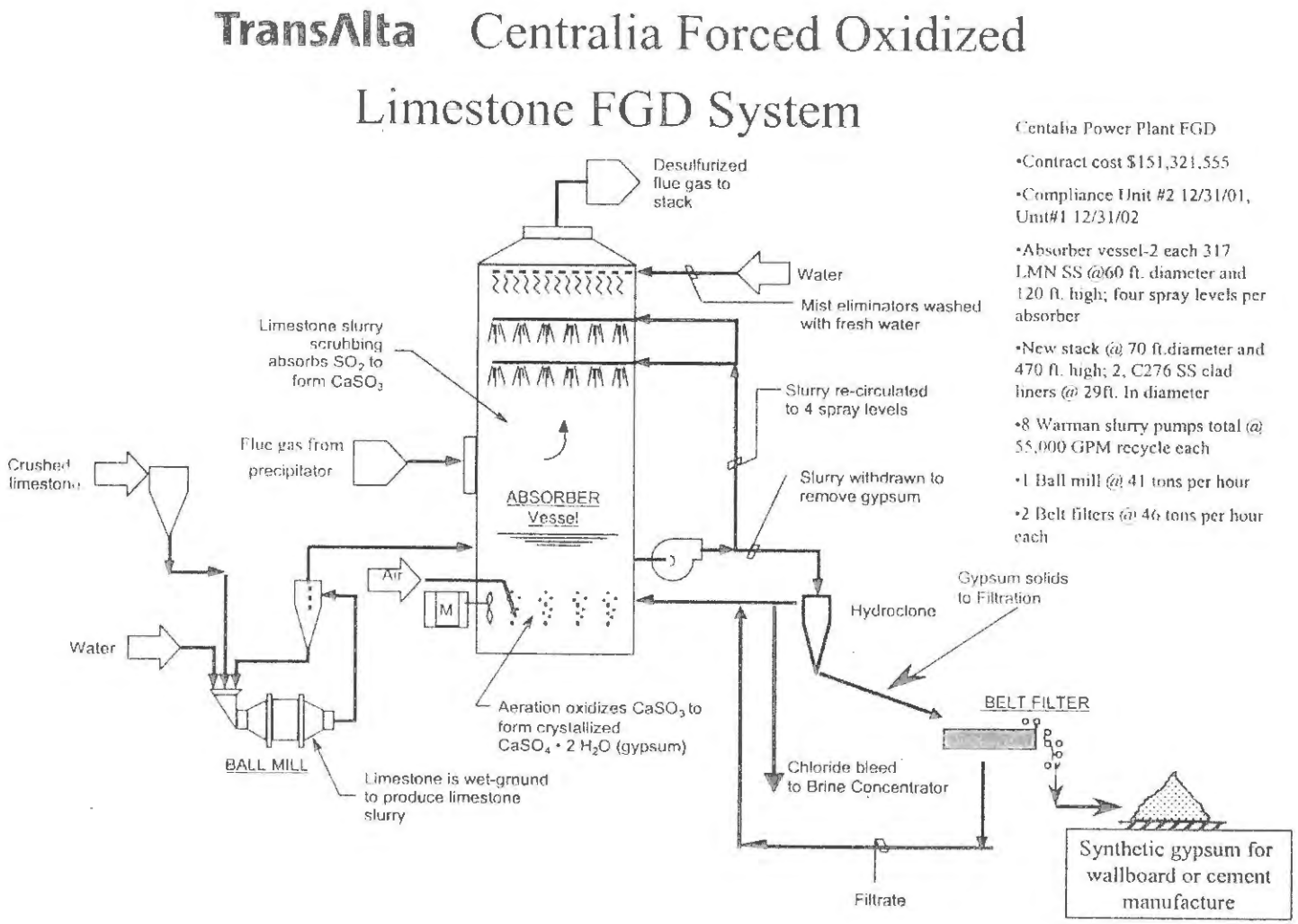
1.	Reopening for Cause" Letter to Permittee:	April 24, 2015
2.	Draft Permit Issued:	November 20, 2015
3.	Proposed Permit Issued:	January 7, 2016
4.	Final Permit Issued:	March 14, 2016

Air Operating Permit SW98-8-R5 (fourth renewal)

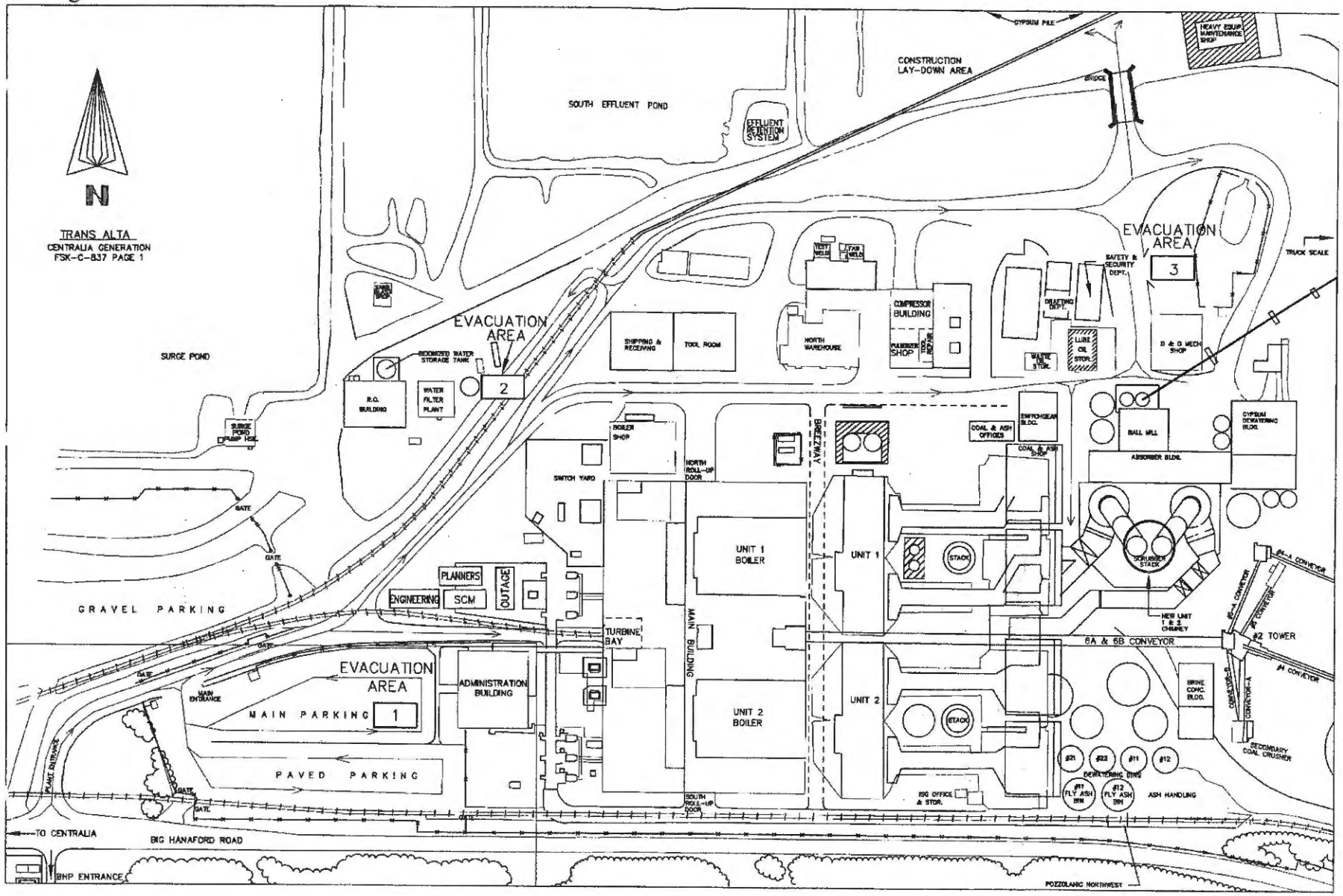
1.	Renewal Permit Application Submitted:	September 13, 2018
2.	Permit Application Deemed Complete:	April 19, 2019
3.	Permit Application Sent to EPA:	July 18, 2019
4.	Draft Permit Issued:	July 18, 2019
5.	Proposed Permit Issued:	August 27, 2019
6.	Final Permit Issued:	October 14, 2019

XII. PLANT DRAWINGS

Drawing 1 – Forced Oxidized Limestone FGD System



Drawing 2 - Coal Plant Schematic



Appendix A
Applicable Requirement Review

CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
60.4200	—	"Am I subject to this subpart?" Informational. This subpart applies to the Coal Unloading Facility Emergency Diesel Sump Pump Engine, Emergency Diesel Generator 2, and the Fire Pump Engine.
60.4201	—	"What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?"
60.4202	—	"What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?"
60.4203	—	"How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?"
60.4204	—	"What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?" Section (b) states that 2007 model year and later non-emergency engines must comply with 40 CFR 60.4201 as applicable. This applies to the Fire Pump Engine. Compliance is met through engine certification and proper operation and maintenance. This engine is Tier 3 EPA certified which meets this requirement. No active requirement.
60.4205	—	"What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?" Section (a) states that the pre-2007 model year engines must meet the requirements in Table 1. This applies to the Coal Unloading Facility Emergency Diesel Sump Pump. Compliance is met through engine certification and proper operation and maintenance. This engine is Tier 2 EPA certified which meets the Table 1 requirement. Section (b) states that 2007 model year and later emergency engines must comply with 40 CFR 60.4202 as applicable. This applies to Emergency Diesel Generator 2. Compliance is met through engine certification and proper operation and maintenance. This engine is Tier 3 EPA certified which meets this requirement. No active requirements in this section.
60.4206	—	"How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?" Informational. No exemption or modification of any other requirement in this section.
60.4207	Req-60, Req-68	"What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?"
60.4208	—	"What is the deadline for importing or installing stationary CI ICE produced in previous model years?"
60.4209	—	"What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?" Requires compliance with monitoring requirements of 40 CFR 60.4211.

CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
60.4209(a)	Req-54	Requires emergency engines that do not meet the requirements for non-emergency engines to install a non-resettable hour meter. This applies to Emergency Diesel Generator 2 which is a 2016 model year certified to EPA Tier 3 for emergency use only.
60.4209(b)	—	Requirements for engines using particulate filters to comply with standards. The engines as this facility do not utilize particulate filters.
60.4210	—	"What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?"
60.4211	"What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?"	
60.4211(a)	Req-64, Req-67	Operation and maintenance requirements.
60.4211(b)	—	For applicable pre-2007 model year engines, requires demonstration of compliance by one of several methods. This is applicable to the Coal Unloading Facility Emergency Diesel Sump Pump Engine and compliance was demonstrated by purchasing a certified engine (option 1). There are no ongoing requirements.
60.4211(c)	—	For 2007 and later model year engines, requires compliance by purchasing an engine certified to the appropriate standards. This is applicable to the Fire Pump Engine and Emergency Diesel Generator 2. Both units were certified to the appropriate standards. There are no ongoing requirements.
60.4211(d)	—	This section applies to engines with a displacement $\geq$ 30 liters per cylinder. The engines at this facility are all smaller than this.
60.4211(e)	—	Requirements for modified or reconstructed engines. There are no modified or reconstructed engines at this facility.
60.4211(f)	Req-56, Req-57, Req-61	Operating limits for emergency engines.
60.4211(g)	Req-64, Req-67	Alternatives for engines not installed, configured, operated or maintained in accordance with manufacturer's instructions.
60.4211(f)	—	Requirements applicable to engines with auxiliary emission control devices. None of the engines at this facility utilize such units.
60.4212	—	"What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?" Testing is not required for any of the engines at this facility.
60.4213	—	"What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?" The engines at this facility are all smaller than this.

CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
60.4214	M26	"What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?" The only remaining applicable requirement is a requirement for Emergency Diesel Generator 2 to keep records of operation in emergency and non-emergency service.
60.4215	—	"What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?"
60.4216	—	"What requirements must I meet for engines used in Alaska?"
60.4217	—	"What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?" This facility does not have approval to utilize special fuels.
60.4218	—	"What parts of the General Provisions apply to me?" Refers to Table 8.
60.4219	—	"What definitions apply to this subpart?" Informational.
Table 1	—	"Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder" Informational listing of the emission standards. This section is applicable to the Coal Unloading Facility Emergency Diesel Sump Pump Engine. Compliance was demonstrated by purchasing a EPA Tier certified engine that exceeds the standards in Table 1.
Table 2	—	"Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder." No engine in this category at the facility.
Table 3	—	"Certification Requirements for Stationary Fire Pump Engines." No engine in this category at the facility. The Fire Pump Engine at this facility is used for non-emergency use as well as fire protection and therefore is not a "fire pump engine" for the purposes of this subpart.
Table 4	—	"Emission Standards for Stationary Fire Pump Engines." The Fire Pump Engine at this facility is used for non-emergency use as well as fire protection and therefore is not a "fire pump engine" for the purposes of this subpart.
Table 5	—	"Labeling and Recordkeeping Requirements for New Stationary Emergency Engines." Not a requirement for the owner/operator.
Table 6	—	"Optional 3-Mode Test Cycle for Stationary Fire Pump Engines." Not a requirement for the owner/operator.
Table 7	—	"Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder." No engine in this category at the facility.
Table 8	—	"Applicability of General Provisions to Subpart IIII." Table 8 was not listed directly in the permit, rather the individual General Provisions were independently identified.

CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
Applicable General Requirements Identified by Table 8		
60.1	—	General applicability of the General Provisions
60.2	—	Definitions
60.3	—	Units and abbreviations
60.4	—	Address. Informational.
60.5	—	Determination of construction or modification
60.6	—	Review of plans
60.7	—	Notification and Recordkeeping. There are no notification requirements applicable to this engine.
60.8	—	Performance tests. No performance tests are required.
60.9	—	Availability of information. Informational
60.10	—	State Authority. Informational.
60.11	P1	Compliance with standards and maintenance requirements. No active requirements, however, the credible evidence provision was included in P1.
60.12	—	Circumvention (masking or concealing emissions that would violate an applicable standard). The only applicable emission standards apply to initial certification.
60.13	—	Monitoring requirements. Only applies to stationary CI ICE with a displacement of ≥30 liters per cylinder.
60.14	—	Modification. Modification is subject to New Source Review.
60.15	—	Reconstruction. Reconstruction is subject to New Source Review.
60.16	—	Priority list
60.17	—	Incorporations by reference
60.18	—	General control device requirements. No control devices.
60.19	—	General notification and reporting requirements. There are no notification requirements applicable to the engines at this facility.

63 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters		
Requirement	**Title V Permit Location**	**Comments**
63.7480	—	"What is the purpose of this subpart?"
63.7485	—	"Am I subject to this subpart?"
63.7485	—	"Am I subject to this subpart?" This subpart is applicable to the Auxiliary Boiler.
63.7490	—	"What is the affected source of this subpart?"
63.7491	—	"Are any boilers or process heaters not subject to this subpart?"
63.7495	—	"When to I have to comply with this subpart?" All applicable compliance dates are past.

63 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters		
Requirement	**Title V Permit Location**	**Comments**
63.7499	—	"What are the subcategories of boilers and process heaters?" Informational. The Auxiliary Boiler is in the "limited-use" subcategory.
63.7500	"What emission limitations, work practice standards, and operating limits must I meet?"	
63.7500(a)	Req-40	Requirements to comply with applicable elements in tables, and general duty clause. Only the general duty clause applies to the Auxiliary Boiler because it is in the "limited-use" subcategory (see 75.000(c)).
63.7500(c)	Req-41	Tune-up requirements and exemption from specific requirements.
63.7500(d)	—	Tune-ups for small boilers.
63.7500(e)	—	Requirements for specific subcategories
63.7500(f)	—	Statement that standards apply to all normal operation. No operating standards applicable to the Auxiliary Boiler.
63.7505	Req-41	"What are my general requirements for complying with this subpart?"
63.7510	Req-41	"What are my initial compliance requirements and by what date must I conduct them?" Applies to the initial tune-up.
63.7515	Req-41	"When must I conduct subsequent performance tests, fuel analyses, or tune-ups?" Only the tune-up requirements apply to the Auxiliary Boiler.
63.7520	—	"What stack tests and procedures must I use?" No stack test is required.
63.7521	—	"What fuel analysis, fuel specification, and procedures must I use?" No requirements for the Auxiliary Boiler.
63.7522	—	"Can I use emissions averaging to comply with this subpart?" Only 1 affected unit at this facility, and no applicable emission limits apply.
63.7525	M14	"What are my monitoring, installation, operation, and maintenance requirements?"
63.7530	—	"How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?" No requirements in this section for units subject only to the work practice standards.
63.7533	—	"Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?" Applies to emission limits. There are no applicable emission limits for the Auxiliary Boiler.
63.7535	—	"Is there a minimum amount of monitoring data I must obtain?" No continuous monitoring requirements for the Auxiliary Boiler.
63.7540	Req-41	"How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?" Section (12) requires a tune-up every 5 years.
63.7541	—	"How do I demonstrate continuous compliance under the emissions averaging provision?" Emissions averaging does not apply.
63.7545	—	"What notifications must I submit and when?" The only applicable requirements was the initial notification of compliance status, which has been completed.
63.7550	R10	"What reports must I submit and when?" Compliance reports must be submitted every 5 years.

63 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters		
Requirement	**Title V Permit Location**	**Comments**
63.7555	M34	"What records must I keep?"
63.7560	M34, M41	"63.7560 In what form and how long must I keep my records?"
63.7565	—	"What parts of the General Provisions apply to me?" Informational
63.7570	—	"Who implements and enforces this subpart?" Informational
63.7575	—	Definitions
Table 1	—	"Emission Limits for New or Reconstructed Boilers and Process Heaters"
Table 2	—	"Emission Limits for Existing Boilers and Process Heaters"
Table 3	Req-41	"Work Practice Standards"
Table 4	—	"Operating Limits for Boilers and Process Heaters"
Table 5	—	"Performance Testing Requirements"
Table 6	—	"Fuel Analysis Requirements"
Table 7	—	"Establishing Operating Limits"
Table 8	—	"Demonstrating Continuous Compliance"
Table 9	—	"Reporting Requirements"
Table 10	—	"Applicability of General Provisions to Subpart DDDDD". Informational.
Table 11	—	"Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011"
Table 12	—	"Table 12 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After May 20, 2011, and Before December 23, 2011"
Table 13	—	"Table 13 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After December 23, 2011, and Before April 1, 2013"

63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
63.6580	—	"What is the purpose of subpart ZZZZ?"
63.6585	—	"Am I subject to this subpart" All of the stationary engines are subject, however no requirements from subpart ZZZZ apply to the units that are also subject to Subpart IIII.

63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
63.6590	—	"What parts of my plant does this subpart cover?" The Black Stop Diesel Generator Engine and Emergency Diesel Generator 1 are subject to requirements from subpart ZZZZ. The Black Stop Diesel Generator Engine is an existing emergency engine > 500 bhp at a major HAP source. Emergency Diesel Generator 1 is an existing emergency engine < 500 hp at a major HAP source.
63.6595	—	"When do I have to comply with this subpart?"
63.6600	—	"What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?" This section exempts emergency stationary RICE from compliance with the emission limits in Tables 1a, 2a, 2c, and 2d, and the operating limits in Tables 1b and 2b. This section provides exemptions but no direct requirements.
63.6601	—	"What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?" No engines in this category at the facility.
63.6602	Req-51, Req-52	"What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?" References the applicable emission limits in Table 2c. The only applicable emission limit category in Table 2c is "Non-emergency, non-black start CI stationary RICE 100≤HP≤300 HP" with a CO emission limit of 230 ppmvd @ 15% O_2.
63.6603	—	"What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?" This facility is a major source.
63.6604	—	"What fuel requirements must I meet if I own or operate a stationary CI RICE?" None of the engines at this facility fall into one of the specific categories listed in this section.
63.6605	Req-55, M42	"What are my general requirements for complying with this subpart?" This section is a general duty clause.
63.6610	—	"By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?" There are no applicable testing requirements for engines at this facility.

63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
63.6611	—	"By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?" No engines in this category at the facility.
63.6612	M4	"By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?" There are no applicable testing requirements for engines at this facility.
63.6615	—	"When must I conduct subsequent performance tests?" Requires subsequent testing as per Table 3. This facility does not have any engines subject to performance testing requirements.
63.6620	—	"What performance tests and other procedures must I use?" This facility does not have any engines subject to performance testing requirements.
63.6625	Req-52, Req-53, Req-54, Req-94	"What are my monitoring, installation, collection, operation, and maintenance requirements?" Only sections (e), (f), and (h), and optionally (i) apply to any engines at this facility. Section (e)(2) and (f) apply to Emergency Diesel Generator 1 only.
63.6630	—	"How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?" The engines at this facility are not subject to any of the limitations or requirements for which a compliance demonstration is required.
63.6635	—	"How do I monitor and collect data to demonstrate continuous compliance?" Continuous compliance monitoring is not required for any of the engines at this facility.
63.6640	"How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?"	
63.6640(a)	Req-51, Req-53	Section (a) requires compliance with applicable requirements in Tables 1a, 1b, 2a, 2b, 2c, and 2d in accordance with Table 6.
63.6640(b)	R4	Deviation reporting requirements. Included as part of routine semiannual reporting.
63.6640(c)	—	Requirements for specific 4SLB and 4SRB. This facility does not have any engines in this category.
63.6640(d)	—	Exemptions for "engine burn-in". No engines at this facility are this new.
63.6640(e)	—	Section (e) requires reporting of deviations from Part 63 "General Provisions" for non-exempted engines. Emergency engines are exempt.
63.6640(f)	Req-56, Req-90	Operating limitations for emergency engines.

63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
63.6645	—	"What notifications must I submit and when?" In accordance with 40 CFR 63.6645(a)(5) the general notification requirements in (a) do not apply to existing emergency engines.
63.6650	R4	"What reports must I submit and when?" The general requirement to report deviations in the semiannual Title V report is found in 63.6650(f).
63.6655	M19, M26	"What records must I keep?" Maintenance and operating records must be kept.
63.6660	VII	"In what form and how long must I keep my records?" This section and 63.10(b) are included in the introductory paragraphs of Section VII.
63.6665	—	"What parts of the General Provisions apply to me?" References Table 8. This section itself is informational and not included in the permit. This section exempts existing emergency engines > 500 bhp at major HAP sources (Black Stop Diesel Generator Engine) from the general provisions. While Emergency Diesel Generator 1 is not specifically exempted, there are no active general requirements for this unit.
63.6670	—	"Who implements and enforces this subpart?" This section is informational.
63.6675	—	"What definitions apply to this subpart?" This section is a reference for other sections and does not contain any directly applicable requirements.
Table 1a	—	"Table 1a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions" No engines in this category at this facility.
Table 1b	—	"Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions" No engines in this category at this facility.
Table 2a	—	"Table 2a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions". No engines in this category at this facility.
Table 2b	—	"Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP" No engines in this category at this facility.

63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
Table 2c	Req-51, Req-52, Req-94, Req-95	"Table 2c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions".
Table 2d	—	"Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions" This facility is a major source of HAP.
Table 3	—	"Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests" There are no engines in the categories listed in Table 3 at this facility.
Table 4	—	"Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests". No engines at this facility are required to conduct performance tests.
Table 5	—	"Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements". None of the engines at this facility are subject to initial compliance demonstrations.
Table 6	Req-53	"Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements". The work practice standard requirements addressed here do not apply to engines > 500 bhp such as the Black Stop Diesel Generator Engine.
Table 7	—	"Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports". The only applicable engines at this facility are existing emergency engines. There are no reporting requirements for existing emergency engines.
Table 8	—	"Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ." Table 8 was not listed directly in the permit, rather the individual General Provisions were independently identified as applicable.
Applicable General Requirements Identified by Table 8		
63.1	—	General applicability of the General Provisions
63.2	—	Definitions
63.3	—	Units and abbreviations
63.4	—	Prohibited activities and circumvention
63.5	—	Construction and reconstruction notification. Construction or reconstruction would require NSR.
63.6(a)	—	Applicability. Informational
63.6(b)(1)-(4)	—	Compliance dates for new and reconstructed sources. Informational
63.6(b)(5)	—	Notification for new or reconstructed sources. Construction or reconstruction would require NSR.
63.6(b)(7)	—	Compliance dates for new and reconstructed area sources that become major sources. Informational. This facility is already a major source.
63.6(c)(1)-(2)	—	Compliance dates for existing sources. Compliance dates have passed.

63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
63.6(c)(5)	—	Compliance dates for existing area sources that become major sources. Informational. This facility is already a major source.
63.6(f)(2)	—	Methods for determining compliance. Informational.
63.6(f)(3)	—	Finding of compliance. Informational
63.6(g)(1)-(3)	—	Use of alternate standard. Informational.
63.6(i)	—	Compliance extension procedures and criteria
63.6(j)	—	Presidential compliance exemption
63.7(a)(1)-(2)	—	Performance test dates. All initial testing has been completed.
63.7(a)(3)	—	CAA section 114 authority
63.7(b)(1)	—	Notification of performance test
63.7(b)(2)	—	Notification of rescheduling
63.7(c)	—	Quality assurance/test plan
63.7(d)	—	Testing facilities
63.7(e)(2)	—	Conduct of performance tests and reduction of data. Informational
63.7(e)(3)	—	Test run duration. Run duration already specified in rule.
63.7(e)(4)	—	Administrator may require other testing under section 114 of the CAA. Informational
63.7(f)	—	Alternative test method provisions. Informational. No reasonable reason to utilize an alternative test method.
63.7(g)	—	Performance test data analysis, recordkeeping, and reporting. Source test report requirements are detailed in R6, however Subpart ZZZZ testing requirements in the permit are primarily informational because all initial testing has been completed.
63.7(h)	—	Waiver of tests. Informational.
63.8(a)(1)	—	Applicability of monitoring requirements.
63.8(a)(2)	—	Performance specifications
63.8(b)(1)	—	Alternative Monitoring.
63.8(b)(2)-(3)	—	Multiple effluents and multiple monitoring systems
63.8(c)(1)	—	Continuous monitoring system (CMS) operation and maintenance. No CMS at this facility.
63.8(c)(1)(ii)	—	Continuous monitoring system parts
63.8(c)(2)-(3)	—	Monitoring system installation
63.8(c)(4)	—	Continuous monitoring system requirements
63.8(c)(6)-(8)	—	CMS requirements
63.8(d)	—	CMS quality control
63.8(e)	—	CMS performance evaluation. Except that §63.8(e) only applies as specified in §63.6645.
63.8(f)(1)-(5)	—	Alternative monitoring method
63.8(f)(6)	—	Alternative to relative accuracy test
63.8(g)	—	Data reduction for CMS

63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
63.9(a)	—	Applicability and State delegation of notification requirements
63.9(b)(1)-(5)	—	Initial notifications. Except that §63.9(b) only applies as specified in §63.6645.
63.9(c)	—	Request for compliance extension
63.9(d)	—	Notification of special compliance requirements for new sources
63.9(e)	—	Notification of performance test
63.9(g)(1)	—	Notification of performance evaluation
63.9(g)(3)	—	Notification that criterion for alternative to RATA is exceeded. Except that §63.9(g) only applies as specified in §63.6645.
63.9(h)(1)-(6)	—	Notification of compliance status
63.9(i)	—	Adjustment of submittal deadlines
63.9(j)	—	Change in previous information submitted. Due to the nature of the equipment at this facility and SWCAA's review, no such notice will be necessary.
63.10(a)	—	Administrative provisions for recordkeeping/reporting
63.10(b)(1)	VII	Record retention
63.10(b)(2)(vi)-(xi)	—	Records
63.10(b)(2)(xii)	—	Record when under waiver
63.10(b)(2)(xiii)	—	Records when using alternative to RATA
63.10(b)(2)(xiv)	—	Records of supporting documentation
63.10(b)(3)	—	Records of applicability determination
63.10(c)	—	Additional records for sources using CEMS
63.10(d)(1)	—	General reporting requirements. Reporting specified as per the applicable standard.
63.10(d)(2)	—	Report of performance test results
63.10(d)(4)	—	Progress reports. No progress reports required.
63.10(e)(1) and (2)(i)	—	Additional CMS Reports
63.10(e)(3)	—	Excess emission and parameter exceedances reports (CEMS)
63.10(f)	—	Waiver for recordkeeping/reporting. Informational.
63.12	—	State authority and delegations
63.13	—	Addresses. Informational
63.14	—	Incorporation by reference
63.15	—	Availability of information

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.9980	—	"What is the purpose of this subpart"
63.9981	—	"Am I subject to this subpart" This facility is subject to this regulation.
63.9982	—	"What is the affected source for this subpart" Defines the affected source. For this facility the Unit 1 and Unit 2 EGU's are classified as "existing".
63.9983	—	"Are any EGUs not subject to this subpart?" None of the exemptions apply to this facility.
63.9984	—	"When do I have to comply with this subpart?" All of the compliance dates have passed.
63.9985	—	"What is a new EGU?" TransAlta's EGUs are not new.
63.9990	—	"What are the subcategories of EGUs?" TransAlta's coal may exceed 8,300 Btu/lb, therefore these units fall into the category of "designed for coal greater than or equal to 8,300 Btu/lb" subcategory – listed elsewhere as "Coal-fired unit not low rank virgin coal."
63.9991	Req-15, Req-20, Req-25, Req-38	"What emission limitations, work practice standards, and operating limits must I meet?" This section refers to the requirements in Tables 1 – 4. Where those requirements are cited, this section that points to those requirements is cited as well.
63.10000	"What are my general requirements for complying with this subpart?"	
63.10000(a)	.Req-15, Req-20, Req-25, Req-37	States that must comply with the requirements of this subpart and includes the startup and shutdown exceptions where work-practice standards apply in lieu of emission limits.
63.10000(b)	Req-38	Requirements to operate consistent with good air pollution control practices for minimizing emissions.
63.10000(c)	—	Initial performance testing requirements. All initial performance testing has been completed; therefore, these requirements are not included in the Air Operating Permit.
63.10000(d)	M9	Requires the generation of a site-specific monitoring plan for any CMS or CEMS used to demonstration compliance with an applicable emission limit. This requirement does not apply to affected sources with existing monitoring plans prepared in accordance with 40 CFR 60 Appendix B, or 40 CFR 75. This facility utilizes a CEMS with a monitoring plan in accordance with 40 CFR 75 for SO_2 to demonstrate compliance with acid gas limitations and therefore this CEMS is exempt from this requirement. The plan elements are considered to be met for Hg sorbent trap monitoring systems installed, operated, and quality-assured in accordance with Appendix A of Subpart UUUUU. This facility utilizes a sorbent trap monitoring system to monitor Hg emissions in accordance with Appendix A of Subpart UUUUU, therefore the plan elements are met. The only remaining requirements are to operate the Hg monitoring system in accordance with the site-specific monitoring plan (i.e. Appendix A).

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollntants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.10000(e)	Req-36	Requirement to conduct periodic tune-ups according to 40 CFR 63.10021(e).
63.10000(f)	—	Requires that EGUs remain subject to this subpart at least 6 months after the EGU met definition of a subject EGU. This section is information and does not contain additional applicable requirements.
63.10000(g)	—	States that EGUs no longer meeting the definition of an EGU subject to this part must comply with any new requirements on the date no longer subject to this subpart. This section is information and does not contain additional applicable requirements.
63.10000(h)	—	Requirements related to EGUs that become subject after April 16, 2015. The only EGUs at this facility were already subject to this subpart as of April 16, 2015 therefore this does not apply to the EGUs at this facility.
63.10000(i)	—	Requirements for EGUs that cease to operate in a manner that causes the EGU to meet the definition of an EGU subject to this subpart. This section is not currently applicable. No change in applicability is anticipated in the permit term.
63.10000(j)	—	Requirement to have operational pollution control equipment as required for the EGU classification (subject or not subject to this subpart) as of the date the relevant standard is applicable. This section is not currently applicable. No change in applicability is anticipated in the permit term.
63.10000(k)	—	Requirement to have operational pollution monitoring equipment as required for the EGU classification (subject or not subject to this subpart) as of the date the relevant standard is applicable. This section is not currently applicable. No change in applicability is anticipated in the permit term.
63.10000(l)	M33, M10	No later than the date an EGU is subject, must have all necessary monitoring in place for PM or non-Hg HAP metals during startup and shutdown. Must collect, record, report, and maintain data for startup and shutdown periods to demonstrate compliance with work practice standards.
63.10000(m)	M33, M10	If using paragraph (2) of startup definition, must have all necessary monitoring in place for PM or non-Hg HAP metals on or before applicability date. Must collect, record, report and maintain applicable data.
63.10000(n)	—	If permanently convert to natural gas or biomass firing, the EGU is no longer subject to this subpart. This section is information and does not contain additional applicable requirements.
63.10005	Req 15, Req-20, Req-25	What are my initial compliance requirements and by what date must I conduct them? Although all initial compliance requirements have been completed, the reference in 63.10005(a) that clarifies that where two emission limits are specified compliance may be demonstrated with either limit, was listed for reference where two limits were specified.

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.10006	When must I conduct subsequent performance tests or tune-ups?	
63.10006(a)	—	Requirements for units using PM CPMS. This facility conducts quarterly testing in lieu of PM CPMS.
63.10006(b)	—	Requirements for LEE units. The EGUs at this facility do not meet LEE requirements, therefore this section is not applicable.
63.10006(c)	M9	Requirement to conduct periodic filterable PM testing or total HAP metals in accordance with Table 5, 63.10007, 63.10000(c) except as provided in 63.10021(d)(1).
63.10006(d)	—	HCl testing requirements for units that do not use CEMS to demonstrate compliance with acid gas limitations. This facility uses a SO_2 CEMS to demonstrate compliance therefore this section is not applicable.
63.10006(e)	—	Requirements for acid gas monitoring for liquid oil-fired EGUs.
63.10006(f)	M9	Time between performance tests. This applies to the quarterly PM testing.
63.10006(g)	—	Emissions averaging provisions. This facility does not conduct emissions averaging and starting in 2021 will only operate one unit.
63.10006(h)	—	LEE test provisions. The EGUs at this facility do not meet LEE requirements, therefore this section is not applicable.
63.10007	What methods and other procedures must I use for the performance test?	
63.10007(a)	M8, M9, R7	Requirements to comply with general test requirements of 63.7 and develop a site-specific test plan. Permanent testing facilities have been installed in accordance with 63.7(d).
63.10007(b)	M8, M9	Requirement to conduct performance tests in accordance with Table 5.
63.10007(c)	—	Requirements for tests for facilities with PM CEMS. This facility utilizes quarterly PM testing option in lieu of PM CEMS, therefore this section is not applicable.
63.10007(d)	M8, M9	Requirement to conduct 3 separate runs and meet the time and volume requirements of Table 1 or 2.
63.10007(e)	M9	This section explains how to use the performance test results to determine compliance with applicable emission limits. M8 contains a general reference to conduct the testing in accordance with 63.10007.
63.10007(f)	M9	Default values for startup and shutdown period CEMS calculations. This would apply to the SO_2 CEMS.
63.10007(f)	M8	Requirement to provide documentation of performance tests to the EPA Administrator upon request.
63.10009	—	May I use emissions averaging to comply with this subpart. This facility has not utilized the option to use emissions averaging.
63.10010	What are my monitoring, installation, operation, and maintenance requirements?	
63.10010(a)	M8	Allowable locations for CEMS and sorbent trap monitoring systems based on the stack configuration. The applicable equipment at this facility are the SO_2 CEMS and the Hg sorbent trap monitoring systems.
63.10010(b)	M9	O_2/CO_2 monitoring requirements.

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.10010(c)	M9	Requirement to monitor flow in accordance with 40 CFR 75. (required for Hg monitoring).
63.10010(d)	M9	Requirement to monitoring moisture in accordance with 40 CFR 75. Moisture data is necessary to correlate wet flow measurements with dry Hg measurements.
63.10010(e)	—	Requirements for sources utilizing HCl and/or HF CEMS. This facility utilizes the SO_2 CEMS option, therefore this requirement does not apply.
63.10010(f)	M9	Requirement to monitor SO_2 in accordance with 40 CFR 75 if utilizing the SO_2 CEMS option for acid gas monitoring. This option is used by this facility. This additional requirements in section (2) do not apply because this facility does not utilize a span of 30 ppm or less.
63.10010(g)	M9	Hg monitoring and data reduction requirements.
63.10010(h)	—	Requirements for source utilizing PM CPMS to demonstrate compliance with an operating limit. This facility does not utilize the PM CPMS option.
63.10010(i)	M9	Requirements for PM CEMS for sources complying with filterable PM limit in lieu of metal HAP limit. This facility utilizes the alternative quarterly PM testing option; however, the PM CEMS option was included in M8 as an alternative.
63.10010(j)	—	Requirements applicable to the use of a metal HAP CEMS. This facility utilizes the alternative quarterly PM testing option.
63.10010(k)	—	Requirements applicable to quarterly HCl and HF testing of liquid oil-fired EGUs.
63.10010(l)	M33	Quality assurance and site-specific monitoring plan requirements for startup monitoring systems.
63.10011	—	Initial compliance demonstration requirements. The references to 63.10011 were removed from Air Operating Permit because all initial demonstrations have been completed.
63.10020	"How do I monitor and collect data to demonstrate compliance?"	
63.10020(a)	—	General requirement to monitor in accordance with the requirements in 63.10020 and the site-specific monitoring plan. These referenced requirements are contained in other sections.
63.10020(b)	M9	Monitoring requirements and exceptions.
63.10020(c)	M9	Lists what data must be excluded from compliance calculations.
63.10020(d)	M9	Requires monitoring at all times with specific exceptions.
63.10020(e)	M10	Startup and shutdown work practice monitoring requirements.
63.10021	"How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?"	
63.10021(a)	—	General requirement to demonstrate compliance with applicable requirements. These referenced requirements are contained in other sections.
63.10021(b)	M9	Describes how to use CEMS data to demonstrate compliance.

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.10021(c)	—	Requirements for use of a PM CPMS. This facility does not utilize a PM CPMS.
63.10021(d)	M9	Contains details related to performance monitoring.
63.10021(e)	Req-36, R11	Tune-up requirements.
63.10021(f)	R11	Repeats the requirements to use ECMPS Client Tool for submittal of a variety of reports, specifies implications of weekend, holiday, and ECMPS outages. Although it does contain some exceptions for holidays, ECMPS system outages, etc, this section is primarily informational in nature, the specific reporting requirements are detailed elsewhere.
63.10021(g)	R4	Requirement to report deviations from emission limits, operating limits, or failed to conduct a tune-up.
63.10021(h)	M9	Requirement to following the startup or shutdown requirements in Table 3 and conduct all required monitoring during startup and shutdown. General requirements in this section that repeat the requirement to comply with another section are not reproduced in the permit.
63.10021(i)	R4	General requirement to report activities during startup and shutdown in accordance with 63.10031.
63.10022	—	"How do I demonstrate continuous compliance under the emissions averaging provision?" This facility has not utilized the option to use emissions averaging.
63.10023	—	"How do I establish my PM CPMS operating limit and determine compliance with it?" This facility does not utilize a PM CPMS.
63.10030	What notifications must I submit and when?	
63.10030(a)	M8, M9, R11	General requirement to submit the notifications required by 40 CFR 63.7, 63.8, and 63.9 as applicable – except that only certain provision of 63.9 apply (see 40 CFR 63.10040 and Table 9). The only remaining notifications are for performance tests and RATAs (30-days prenotification required for each in accordance with Table 9).
63.10030(b)	—	Initial notification deadline for existing units. Initial notifications have been submitted.
63.10030(c)	—	Initial notification deadline for "new" units. Initial notifications have been submitted.
63.10030(d)	M8	Performance test notification.
63.10030(e)	—	Initial Notice of Compliance Status report requirements. All initial notifications have been submitted.
63.10030(f)	—	Requirement to submit the notification in 40 CFR 63.10000(h)(2) and (i)(2) that apply. This is applicable to newly applicable EGUs and EGUs that modify their operation such that they are no longer subject to this subpart. Both units at this facility are "existing" and no change in applicability is anticipated in the permit term.
63.10031	What reports must I submit and when?	

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.10031(a)(1)	R11	Hg CMS reporting requirements found in Appendix A are referenced here.
63.10031(a)(2)	—	Not applicable because this facility does not elect to monitor HCl and/or HF continuously. Instead, this facility continuously monitors SO_2 as a surrogate for HCl.
63.10031(a)(3)	—	Not applicable because this facility conducts quarterly PM stack tests instead of operating a PM CEMS.
63.10031(a)(4)	—	Not applicable because this facility conducts quarterly PM stack tests instead of operating a PM CEMS.
63.10031(a)(5)	R11	SO_2 CEMS reporting requirements.
63.10031(b)	R11	Semiannual reporting requirements.
63.10031(c)	R11	Semiannual report contents.
63.10031(d)	R11	Excess emissions and deviation reporting. Re-states the requirement in 40 CFR 63.10031(c)(1) to include the CMS summary report from 63.10(e)(3)(vi) in the semiannual report, and re-states the requirement from 40 CFR 63.10031(g) to report the applicable data elements from Section 13 of Appendix E in the quarterly reports that replace the semiannual reports in 2024.
63.10031(e)	R4	Requirement to report deviations in the semiannual Title V report unless the deviation has been reported in the semiannual or quarterly Subpart UUUUU reports and these reports are submitted with, or as part of, the semiannual Title V report.
63.10031(f)	R4	Compliance test reporting. The only applicable test is the filterable PM testing.
63.10031(f)(1)	R4	RATA test reporting. This facility does not have, and is not likely to install, PM, HCl, or HF CEMS, therefore references to these systems were removed.
63.10031(f)(2)	—	Provisions for commons stacks. This facility does not have any common stacks.
63.10031(f)(3)	—	Reserved
63.10031(f)(4)	R4	Semiannual compliance reports. This section re-states the requirement to submit semiannual reports in accordance with 63.10031(b) – (d) and the initial Notice of Compliance Status (NCS) reports required by 63.10030(e) and adds that they must be submitted as PDF files. All applicable NCS have been submitted.

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.10031(f)(5)	—	Requires all reports not in 63.10031(f), (f)(1), (f)(2) and (f)(4) to be submitted to the Administrator at the applicable address listed in 63.13. This requirement is at odds with 63.10021(f) which states that all reports must be submitted electronically using the ECMPS Client Tool, and the specific reporting requirements listed in the applicable reporting sections and Table 8. Because this section appears to be at odds with the intent of the revisions meant to simply report submission published in the Federal Register September 9, 2020, and is directly at odds with other submission requirements, it was not included in the Title V permit.
63.10031(f)(6)	R11	This section contains details of how to submit reports to ECMPS. Since it appears that all reports must be submitted to ECMPS, this requirement was included in the first paragraph of R11 as applicable to all reports.
63.10031(g)	R11	Details for quarterly report submissions that begin in 2024.
63.10031(h)	—	Initial Notice of Compliance Status reports submitted on or after January 1, 2024. All initial reports have been completed.
63.10031(i)	R11	This section is applicable to this facility because this facility uses the "paragraph (2)" definition of startup.
63.10031(j)	—	Applicable if use PM CEMS. This facility does not use PM CEMS.
63.10031(k)	—	Applicable if use PM or HAP metals CEMS. This facility does not use PM or HAP metal CEMS.
63.10032	What records must I keep?	
63.10032(a)	M10, M37	Records of notifications and reports.
63.10032(b)	M10	CEMS and CPMS recordkeeping.
63.10032(c)	M10	Requires maintaining records of the information listed in Table 7.
63.10032(d)	M10	Of the 3 requirements listed, only the requirement to keep records of monthly fuel use applies to this facility.
63.10032(e)	—	Recordkeeping for emissions averaging. This facility does not utilize emissions averaging.
63.10032(f)	M10	Startup and shutdown period records.
63.10032(g)	M10	Malfunction records.
63.10032(h)	M10	Records of responses to malfunctions.
63.10032(i)	M10	Records of fuel use during startup and shutdown.
63.10032(j)	—	Recordkeeping to prove EGU qualifies as limited-use liquid oil-fired.
63.10033	M10	Record form and retention requirements.
63.10040	—	Informational. Indicates that Table 9 shows which general provisions from part 63 apply.
63.10041	—	Who implements and enforces this subpart? This section does not contain applicable requirements.
63.10042	Req-15, Req-20, Req-25, Req-37	Definitions. The definition of "startup" contains two options and is relevant to several requirements.

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
Table 1	—	Emission Limits for New or Reconstructed EGUs.
Table 2	Req-15, Req-20, Req-25, M9	Emission Limits for Existing EGUs
Table 3	Req-36, Req-37, Req-38, Req-41, M9	Work Practice Standards
Table 4	—	Operating Limits for EGUs – applies only to PM CPMS. This facility does not use PM CPMS.
Table 5	Req-15, Req-20, Req-25, M9	Performance Testing Requirements
Table 6	—	Establishing PM CPMS Operating Limits. This facility does not use PM CPMS.
Table 7	Req-36, M9	Demonstrating Continuous Compliance.
Table 8	R4, R11	Reporting Requirements.
Table 9	M8, M9, M10	Applicability of General Provisions to Subpart UUUUU.
Appendix A	M9	Hg Monitoring Provisions.
Appendix B	—	HCl and HF Monitoring Provisions. This facility has elected to continuously monitor SO_2 in lieu of HCl and HF.

Second Revision of BART Order No. 6426		
Condition	**Title V Permit Location**	**Comments**
1.1	Req-27b	NO_X limits.
1.2	Req-27b	Requirement to calculate the 30-day rolling average in accordance with Condition 5.
1.3	—	Informational. Explains that the Permittee is not limited in how to achieve compliance with the NO_X limits.
2.1	Req-30	Ammonia emission limit
2.2	—	Informational. Explains that the injection of urea to meet the NO_X emissions limit is at the Permittee's discretion.
3.1	Req-31	End of coal burning by first unit.
3.2	Req-31	End of coal burning by second unit
3.3	Req-27b	References the requirement to comply with Condition 1.1.3.
3.4	Req-31	Describes when Conditions 3.1 and 3.2 would not apply.
4.1 except 4.1.4	M8	Ammonia testing requirements

Second Revision of BART Order No. 6426		
Condition	**Title V Permit Location**	**Comments**
4.1.4	Req-30	Describes how compliance with the 30-day rolling average ammonia limit is determined.
5	Req-27b, M9	Describes how NO_X emissions are monitored and averaged for compliance with the BART NO_X limit.
6	R9	Reporting the end of coal firing in each boiler.
7	R9	Urea usage letter
8	R1	BART Order malfunction emission exceedance reports
9.1.1 & 9.1.2	R3	BART Order quarterly reports
9.1.3	R7	Ammonia test reports must be submitted with 45 days of test completion.
9.2	R3	Emission monitoring report requirements.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-132:
Mercury in Fishes in National Parks Report

USGS
science for a changing world

Prepared in cooperation with the National Park Service, Air Resources Division

Mercury in Fishes from 21 National Parks in the Western United States—Inter- and Intra-Park Variation in Concentrations and Ecological Risk



Open-File Report 2014–1051

U.S. Department of the Interior
U.S. Geological Survey

Cover: Reflection Lake at Mount Rainier National Park. Photograph taken by Collin A. Eagles-Smith, U.S. Geological Survey, July 31, 2012.

Mercury in Fishes from 21 National Parks in the Western United States—Inter- and Intra-Park Variation in Concentrations and Ecological Risk

By Collin A. Eagles-Smith, James J. Willacker Jr., and Colleen M. Flanagan Pritz

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Open-File Report 2014–1051

U.S. Department of the Interior
U.S. Geological Survey

U.S. Department of the Interior
SALLY JEWELL, Secretary

U.S. Geological Survey
Suzette M. Kimball, Acting Director

U.S. Geological Survey, Reston, Virginia: 2014

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Conversion Factors

SI to Inch/Pound

Multiply	By	To obtain
	Length	
centimeter (cm)	0.3937	inch (in.)
millimeter (mm)	0.03937	inch (in.)
meter (m)	3.281	foot (ft)
kilometer (km)	0.6214	mile (mi)
kilometer (km)	0.6214	mile (mi)
	Area	
acre (ac)	0.0015625	square mile (mi^2)
	Mass	
gram (g)	0.03527	ounce, avoirdupois (oz)

Temperature in degrees Celsius (°C) may be converted to degrees Fahrenheit (°F) as follows:

$$°F=(1.8\times°C)+32$$

Abbreviations and Acronyms

dw	dry weight
ww	wet weight
Hg	mercury
THg	total mercury
MeHg	methylmercury
LSM	least-square mean
NP	national park
NPS	National Park Service
CARE	Capitol Reef National Park
CRLA	Crater Lake National Park
DENA	Denali National Park
GLBA	Glacier Bay National Park
GLAC	Glacier National Park
GRCA	Grand Canyon National Park
GRTE	Grand Teton National Park
GRBA	Great Basin National Park
GRSA	Great Sand Dunes National Park
LACL	Lake Clark National Park
LAVO	Lassen Volcanic National Park
MEVE	Mesa Verde National Park
MORA	Mount Rainer National Park
NOCA	North Cascades National Park
OLYM	Olympic National Park
ROMO	Rocky Mountain National Park
SEKI	Sequoia – Kings Canyon National Park
WRST	Wrangell – St. Elias National Park
YELL	Yellowstone National Park
YOSE	Yosemite National Park
ZION	Zion National Park

Mercury in Fishes from 21 National Parks in the Western United States—Inter- and Intra-Park Variation in Concentrations and Ecological Risk

By Collin A. Eagles-Smith[1], James J. Willacker[1], Jr., and Colleen M. Flanagan Pritz[2]

Abstract

Mercury (Hg) is a global contaminant and human activities have increased atmospheric Hg concentrations 3- to 5-fold during the past 150 years. This increased release into the atmosphere has resulted in elevated loadings to aquatic habitats where biogeochemical processes promote the microbial conversion of inorganic Hg to methylmercury, the bioavailable form of Hg. The physicochemical properties of Hg and its complex environmental cycle have resulted in some of the most remote and protected areas of the world becoming contaminated with Hg concentrations that threaten ecosystem and human health. The national park network in the United States is comprised of some of the most pristine and sensitive wilderness in North America. There is concern that via global distribution, Hg contamination could threaten the ecological integrity of aquatic communities in the parks and the wildlife that depends on them. In this study, we examined Hg concentrations in non-migratory freshwater fish in 86 sites across 21 national parks in the Western United States. We report Hg concentrations of more than 1,400 fish collected in waters extending over a 4,000 kilometer distance, from Alaska to the arid Southwest. Across all parks, sites, and species, fish total Hg (THg) concentrations ranged from 9.9 to 1,109 nanograms per gram wet weight (ng/g ww) with a mean of 77.7 ng/g ww. We found substantial variation in fish THg concentrations among and within parks, suggesting that patterns of Hg risk are driven by processes occurring at a combination of scales. Additionally, variation (up to 20-fold) in site-specific fish THg concentrations within individual parks suggests that more intensive sampling in some parks will be required to effectively characterize Hg contamination in western national parks.

Across all fish sampled, only 5 percent had THg concentrations exceeding a benchmark (200 ng/g ww) associated with toxic responses within the fish themselves. However, Hg concentrations in 35 percent of fish sampled were above a benchmark for risk to highly sensitive avian consumers (90 ng/g ww), and THg concentrations in 68 percent of fish sampled were above exposure levels recommended by the Great Lakes Advisory Group (50 ng/g ww) for unlimited consumption by humans. Of the fish assessed for risk to human consumers (that is, species that are large enough to be consumed by recreational or subsistence anglers), only one individual fish from Yosemite National Park had a muscle Hg concentration exceeding the benchmark (950 ng/g ww) at which no human consumption is advised. Zion, Capital Reef, Wrangell-St. Elias, and Lake Clark National Parks all contained sites in which most fish exceeded benchmarks for the protection of human and wildlife health. This finding is particularly

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concerning in Zion and Capitol Reef National Parks because the fish from these parks were speckled dace, a small, invertebrate-feeding species, yet their Hg concentrations were as high or higher than those in the largest, long-lived predatory species, such as lake trout. Future targeted research and monitoring across park habitats would help identify patterns of Hg distribution across the landscape and facilitate management decisions aimed at reducing the ecological risk posed by Hg contamination in sensitive ecosystems protected by the National Park Service.

Introduction

Mercury (Hg) is among the most widespread environmental contaminants, distributed at a global scale from natural sources, such as volcanic eruptions and from anthropogenic sources such as emissions followed by atmospheric deposition (Driscoll and others, 2013) and at local or regional scales from current and historic mining activities (Singer and others, 2013). When reactive forms of inorganic Hg are deposited or transported to aquatic habitats, microbial processes can convert the inorganic Hg to methylmercury (MeHg), an organic Hg form that efficiently biomagnifies through food webs (Lavoie and others, 2013) and is a potent neurotoxin (Clarkson and Magos, 2006; Bennett and others, 2009; Wiener and others, 2012). The prevalence and toxicity of Hg make it a serious threat to both wildlife and humans. More than 16 million lake acres and 1 million river miles are under fish consumption advisories due to Hg contamination in the United States, and 81 percent of all fish consumption advisories were issued because of Hg contamination (U.S. Environmental Protection Agency, 2013). Mercury affects numerous physiological processes in vertebrate wildlife and humans, particularly neurological function, but it also can have a deleterious influence on cardiovascular, renal, and endocrine systems. Although the toxicological responses are particularly damaging to developing individuals, elevated Hg exposure also can have fitness consequences in adults through impairment of reproduction (Clarkson and Magos, 2006). Symptoms can occur at exposure levels commonly observed in the environment, and can result in reduced foraging efficiency, survival, or reproductive success (Burgess and Meyer, 2008; Crump and Trudeau, 2009; Wiener and others, 2012).

The widespread transport of Hg through atmospheric and hydrologic pathways, coupled with its potential for environmentally induced “activation” to a highly bioaccumulative and toxic species, is important because it suggests that even remote and protected environments may be at risk to ecological harm from Hg (Lamborg and others, 2002; Schuster and others, 2002). In fact, increasing evidence indicates that Hg contamination of remote and protected environments is not uncommon. For example, total Hg (THg) concentrations in arctic char (*Salvelinus alpinus*) and lake trout (*S. namaycush*) from lakes in Nunavut Canada have up to 1,400 nanograms per gram wet weight (ng/g ww) (Swanson and Kidd, 2010), and THg concentrations in mean northern pike (*Esox lucius*) from remote sites in Alaska have been reported above 1,800 ng/g ww (Duffy and others, 1999). At some of these remote sites, THg concentrations are routinely above the highest benchmarks for risk to human consumers (Jewett and Duffy, 2007). Similarly, Hg concentrations in fish from several western national parks have previously been reported to exceed human and wildlife health thresholds (Landers and others, 2008). Because many remote and protected areas provide refuge from development and human disturbance, they often support high densities of rare and sensitive wildlife species. As a result, the ecological consequences of elevated Hg in these locations could be particularly harmful from a conservation perspective.

National Park Service (NPS) lands are among the most pristine natural areas in the United States, protecting more than 84 million acres of diverse aquatic and terrestrial habitats. This is particularly true for the Western United States and Alaska, which only contain about 32 percent of national park units, yet account for approximately 89 percent of the total land area managed by the NPS. Because such a large proportion of NPS land is in the West, ecological stressors that are pervasive across the region could disproportionately affect NPS resources. Mercury contamination is among those stressors, because many areas of the Western United States are subject to Hg contamination at levels of concern for both human and ecosystem health (Peterson and others, 2007). Moreover, recent work has shown that some remote, high-altitude water bodies in western national parks contain fish with Hg concentrations that exceed toxicological thresholds for both humans and wildlife (Schwindt and others, 2008). However, the extent of contamination across western parks still lacks a systematic characterization and assessment of risk. Furthermore, it remains unclear whether variation in Hg concentrations in fish from remote national parks is more related to local, site- or park-specific characteristics, or broader regional characteristics. Additionally, spatially expansive baseline information is needed in order to evaluate the response of isolated environments to the Mercury and Air Toxics Standards (MATS), implemented by the U.S. Environmental Protection Agency (EPA), which aims to reduce Hg emissions from powerplants by 90 percent. Understanding how variation in fish Hg concentrations is distributed across local and regional scales will facilitate a better understanding of potential mitigation and management options.

As the first step toward better understanding the distribution of Hg across aquatic communities in western national parks, we measured Hg concentrations in fish from 21 different national parks in the Western United States and Alaska (fig. 1). We primarily targeted fish from remote, high altitude lake habitats with limited hydrological connectivity to upstream watersheds in order to minimize watershed scale processes that may potentially confound our assessment of local fish Hg exposure and the relative influence of local versus regional and global processes. Our primary objectives were as follows:

- *Objective 1:* Compare fish Hg concentrations among western national parks, and among sites within western national parks
- *Objective 2:* Determine whether variation in fish Hg concentrations in western national parks is more evident at local site and park scales, compared to broader regional scales;
- *Objective 3:* Evaluate fish Hg concentrations in western national parks with respect to a range of wildlife and human health exposure thresholds.

Because lakes with limited upstream connectivity were preferentially sampled, estimates of variability among lakes may be reduced relative to a random sampling of water available bodies, particularly at local and park scales. Furthermore, the hierarchical spatial design of the current study, combined with the gradient in landscape types, altitudes, and fish species that occur over such an extensive study area, preclude examination of the specific drivers of Hg variation at various scales, and investigating these factors was beyond the scope of the current study.

Methods

Study Sites and Sample Collection

This study focused on remote, fish-bearing aquatic habitats in the Western United States. We sampled 86 individual sites from 21 national parks in 10 Western States (fig. 1, table 1). Our primary target habitats were remote, high-altitude lakes containing non-migratory fish populations in order to reduce the likelihood that fish Hg concentrations are reflective of exposure that occurred elsewhere. However, some parks, especially Great Basin National Park (NP) and those in the arid Southwest, lacked similar aquatic habitats; therefore, we also sampled flowing rivers and streams in a few parks where lake habitats were unable to be sampled.

Fish were collected in 2008, 2009, 2011, and 2012 by NPS personnel following standardized protocols as described in this paragraph below. The intensive sampling at Mount Rainier in 2012 was conducted by U.S. Geological Survey (USGS) staff as part of a focused study in that park, examining a range of food web components. Whereas most of the sites were only sampled during 1 of the 4 years, 10 lakes within four parks (Lake Clark, Olympic, Rocky Mountain, Sequoia-Kings Canyon) were sampled in 2 separate years in order to examine temporal variation within a subset of lakes (table 1). Depending on the characteristics of a site, and its associated access logistics, fish were sampled using variable-mesh or fixed-mesh gillnets, hook and line, or beach seines. Because of ecological limits to the distribution of fish species across the entire western region of North America, identical species did not exist at all sites. Instead, we focused on targeting four primary species (brook trout [*S. fontinalis*], cutthroat trout [*Oncorhynchus clarkii*], rainbow trout [*O. mykiss*], and lake trout) that occurred across as many sites as possible. In sites where those species did not occur, we sampled the most abundant resident species that were found, trying where possible to match the ecological niche of at least one of our primary species. Once fish were collected, they were immediately wrapped in chemically cleaned aluminum foil and sealed in individually labeled polyethylene zip bags. Fish in the field were immediately placed on wet or dry ice until transport to the laboratory, where they were stored at -20°C until processing and analysis.

Sample Processing and Mercury Determination

In the laboratory, we thawed each fish to room temperature, measured standard length (SL) to the nearest millimeter, and mass to the nearest 0.1 g. From each fish with greater than 100 mm SL, we dissected 5–10 g of skinless axial muscle using nitric acid and deionized-water-rinsed scalpels, scissors, and forceps. We then rinsed each muscle sample in deionized water to remove any surface contaminants, blotted them dry with clean, lint-free wipes, and weighed them on an analytical balance to the nearest 0.0001 g. Fish with less than 100 mm SL were processed as whole-body samples. For these, we removed stomach contents and thoroughly cleaned the surface of the fish with deionized water, then blotted dry and weighed as described above for muscle tissue. We chose to process and analyze fish less than 100 mm SL as whole fish because they often lacked adequate muscle tissue for analysis. Moreover, robust conversion equations exist for translating between whole-body fish and muscle THg concentrations (Peterson and others, 2005, 2007); thus, the whole-body samples were still comparable to the muscle samples. Once muscle or whole-body samples were cleaned and weighed, we placed them in a drying oven at 50 °C until a constant mass was achieved, typically 48 h. We subsequently removed the sample from the drying oven and allowed them to cool to room temperature in a desiccator. Once cool, we measured the dry mass of each sample to the nearest 0.0001 g, and homogenized each to a fine powder with scissors and a ceramic mortar and pestle. The homogenized samples were stored in a desiccator until chemical analysis.

We determined THg concentrations of each sample following EPA method 7473 (U.S. Environmental Protection Agency, 2000) on a Milestone tri-cell DMA-80 Direct Mercury Analyzer (Milestone, Inc., Monroe, Connecticut, U.S.A.). Briefly, we used an integrated sequence of drying (250 °C for 30 s), thermal decomposition (650 °C for 90s), catalytic conversion, and then amalgamation in a gold trap, followed by cold vapor atomic absorption spectroscopy. Quality-assurance measures included analysis of two certified reference materials (either dogfish muscle tissue [DORM-4; National Research Council of Canada, Ottawa, Canada], or dogfish liver [DOLT-3; National Research Council of Canada, Ottawa, Canada]), two system and method blanks, and two duplicates-per-batch of 30 samples. Recoveries (± standard error) averaged 102.8 ± 0.6 percent (n = 88) and 97.83 ± 1.06 percent (n = 128) for certified reference materials and calibration checks, respectively. Absolute relative percent difference for all duplicates averaged 3.31 ± 0.40 percent.

Statistical Analyses

Unless otherwise noted, all statistical analyses were conducted on dry-weight THg concentrations to minimize inconsistencies resulting from variable moisture contents of individual fish. However, to facilitate comparisons with other work, we present wet weight THg concentrations in the text and figures. Fish length is often positively correlated with Hg concentrations, which can confound direct comparisons of fish Hg concentrations among locations with different sized fish. In order to make spatial comparisons among and within parks, we first evaluated whether size adjusting THg concentrations was necessary for each species of fish at each sampling site. To make this determination, we developed decision rules based on a combination of the strength of regression coefficients (R^2) and the small sample-size corrected Akaike's Information Criterion (AIC_c) for length versus THg concentration (dry weight, $\log_{10}$-transformed) regression models from each species-site combination. No size adjustment was made for models with R^2 less than 0.20. For regression models with R^2 greater than 0.20, we compared the regression model with a null model using AIC to assess whether including fish length as a variable improved the likelihood of predicting fish THg concentrations. If the difference between the regression and null AIC_c values (ΔAIC_c) was less than 2, we proceeded with size adjusting individual THg concentrations using linear regression. We also used AIC-based model assessment to determine whether sampling year (where available) influenced the relationship between size and Hg concentrations by including a year-by-size interaction. The year-by-size interaction failed to improve the plausibility of the size-Hg relationship in all cases; thus for size adjustment, we lumped all fish from a population regardless of year sampled.

The variation in sizes and species of fish collected across sites complicated direct comparisons of size-adjusted THg concentrations for all fish simultaneously. Therefore, using length-frequency histograms, we classified fish species into three different size categories (50, 200, and 400 mm SL), thus minimizing extrapolation of THg concentrations outside the range of sizes observed for each species. Mercury concentrations in smallest size category of fishes (speckled dace [*Rhinichthys osculus*], threespine stickleback [*Gasteristeus aculeatus*], and torrent sculpin [*Cottus rhotheus*]) were adjusted to the concentration predicted at 50 mm SL for each individual. Mercury concentrations in the intermediate size category of fishes (arctic grayling [*Thymallus arcticus*], brook trout, brown trout [*Salmo trutta*], cutthroat trout, Dolly Varden [*S. malma malma*], golden trout [*O. mykiss aquabonita*], kokanee [*O. nerka*], rainbow trout), were adjusted to the concentration predicted at 200 mm SL for each individual. Mercury concentrations in the largest size category of fishes (bull trout [*S. confluentus*], lake trout, lake whitefish [*Coregonus clupeaformis*], and northern pike) were adjusted to the concentration predicted at 400 mm SL for each individual. To standardize THg concentrations to the appropriate sizes, we used the linear regression equations for each site-species combination, then added the residuals from

each individual fish to its predicted concentration in order to incorporate the unexplained variation back into the estimate. For those fish sampled from sites where there was no meaningful Hg-size relationship, we used the un-adjusted Hg concentrations for each individual.

To compare Hg concentrations among parks and sites within parks, we constructed separate mixed effects, nested general linear models for each of the three size classes (50, 200, and 400 mm SL) with park and site (nested within park) included as fixed effects, and species included as a random effect in each model to statistically account for variation due to different species being collected across sites. In addition to comparing model-adjusted fish THg concentrations among parks and sites within parks, we used the model-adjusted THg concentrations at sites and parks to examine how variation in THg concentrations was partitioned across a gradient of spatial scales. To do this, we evaluated the coefficient of variation (CV) for (1) all fish within a site using individual fish THg concentrations, (2) all sites within a park using model-generated least-square mean (LSM) THg concentrations for each site, and (3) all parks using model-generated LSM Hg concentrations for each park. By comparing the CVs from each of these scales with t-tests (two-sample in comparison 1 and 2, one-sample in comparison 3), we evaluated whether within-lake processes, within-catchment processes, or within-region processes accounted for the most variation in THg concentrations.

In order to evaluate temporal variation in the subset of 10 sites that were sampled in more than 1 year, we used analysis of covariance (ANCOVA), which tested whether fish Hg concentrations were different between years for each lake, while statistically controlling for fish length. Therefore, we included standard length as a covariate in the models. The initial sampling event for each site varied between 2008, 2009, and 2011 depending on the park. The final sampling for all sites was 2012. Because of this, our goal was not to test whether there were consistent year effects, but simply to evaluate how Hg concentrations within a site might differ between two distinct years regardless of which years those were.

Risk Benchmark Values

In addition to examining spatial and temporal variation in fish THg concentrations across parks, we also evaluated the threat Hg might pose at each site to the health of fish, piscivorous wildlife, and humans by comparing measured and modeled THg concentrations to a range of established benchmarks of toxicity to different taxonomic groups.

Fish

We compared whole-body Hg concentrations in fish to a no-observed-effects-residue (NOER) of 200 ng/g ww (Beckvar and others, 2005) and a lowest-observed-effects-residue (LOER) of 300 ng/g ww (Sandheinrich and others, 2011) to assess potential risks of Hg exposure to fish themselves. The NOER threshold identifies the Hg concentration in fish tissues below which fish should not experience deleterious effects of Hg exposure on reproduction, growth, or survival. In contrast, the LOER threshold indicates the concentration above which sublethal endpoints of Hg exposure, including alterations to reproductive health, have been documented in laboratory and field studies of fish.

Birds

Birds are sensitive to the toxicological effects of MeHg exposure, and piscivorous birds are among the taxa most commonly at risk because of their high trophic position. However, robust data on the dietary Hg exposure thresholds that result in deleterious effects exist for very few bird species. Moreover, there is considerable evidence of substantial variability in the sensitivity of different bird

species to Hg exposure (Heinz and others, 2009). Therefore, accurately extrapolating risk across a range of unique species can be difficult and may result in low confidence estimates. This is particularly problematic in studies such as this one, where no single piscivorous bird species with well-documented toxicological responses to Hg exposure extends across such an expansive spatial extent, nor over such a range of habitats. Therefore, our approach was to establish a baseline of risk in a well-studied avian piscivore, then evaluate the likely range of risk for arbitrary taxa that are more and less sensitive to Hg than the baseline species. Arguably the most robust information on avian piscivore toxicological responses to Hg exposure across a range of scales of ecological organization exists for the common loon (*Gavia immer*), which has been intensively studied in field and laboratory settings for several decades (Kenow and others, 2008; Mitro and others, 2008; Scheuhammer and others, 2008; Kenow and others, 2011). This extensive research on the behavioral and reproductive impacts of Hg contamination has resulted in the development of robust dietary benchmarks for identifying ecological risk of Hg to common loons at a range of deleterious endpoints. These studies, coupled with other work on interspecific sensitivity to Hg exposure (Heinz and others, 2009), suggest that loons are moderately sensitive to Hg exposure in comparison to some other taxa. Therefore, we utilized the common loon dietary screening benchmark of 180 ng Hg/g ww in whole-body prey-fish (Depew and others, 2012b) as our baseline indicator of Hg risk to moderately sensitive avian consumers. Without solid quantitative comparisons of relative sensitivity among species, we chose a conservative approach of scaling the loon screening value down and up by 50 percent in order to estimate potential risk to bird species that are more or less sensitive to Hg exposure than the common loon. Thus, we assessed risk to avian consumers by comparing Hg concentrations in whole-body fish to 90 (high sensitivity), 180 (moderate sensitivity), and 270 ng Hg/g ww (low sensitivity) benchmarks. We recognize that this scaling is somewhat arbitrary in that it is not calibrated to specific avian species responses, but we chose this approach to better encompass the range of potential risk depending on the species that might occur at any given area. Much work is still needed to refine the scientific understanding of interspecies differences in sensitivity, but we use Heinz and others (2009) as the baseline for identifying some taxonomic groups that may fall into each classification. Based on that study of 27 bird species, piscivorous taxa that can be categorized as high sensitivity and that are found in some of the parks studied include osprey (P*andion haliaetus*), white ibis (*Eudocimus albus*), and snowy egret (*Egretta thula*). Species that can be categorized as low sensitivity include hooded merganser (*Lophodytes cucullatus*) and double-crested cormorant (*Phalacrocorax auritus*). Besides common loon, other species with probable moderate sensitivity include common tern (*Sterna hirundo*), royal tern (*Sterna maxima*), and great egret (*Ardea alba*).

Humans

We assessed risk of Hg exposure to human consumers of fish by comparing Hg concentrations in fish muscle to the EPA's tissue residue criterion for Hg (300 ng/g ww) and two benchmarks recommended by the Great Lakes Advisory Group (GLAG) for limiting the risk of Hg exposure to anglers (Great Lakes Advisory Group, 2007). The lower benchmark (50 ng/g ww) represents the concentration of Hg in fish muscle below which unrestricted consumption of fish poses no risk to consumers. The higher benchmark (950 ng/g ww) represents the concentration of Hg in fish muscle above which GLAG recommends that no consumption occur.

Risk Estimation

We assessed risk to fish, avian consumers, and humans using two approaches. First, we compared whole-body (fish and avian risk assessments) or muscle (human risk assessment) Hg concentrations in fish to each of the reference values discussed above (two fish, three avian, and three human benchmarks) and enumerated the proportion of individuals exceeding each benchmark at each site, park, and across parks. This analysis provides an overview of Hg risk in all parks and sites sampled, but does not account for other factors that influence Hg risk. In particular, because Hg concentrations can be strongly influenced by fish size, it is important to understand how risk varies across the size spectra of the fish communities. Therefore, in the populations (that is, species-site combinations) where size was correlated with Hg concentrations, we used a second approach utilizing the size-Hg relationships to model the Hg concentration of each fish sampled from a population at 1 mm increments over the range of sizes observed in that population. We then compared these modeled fish Hg concentrations to each of the eight benchmarks at 1 mm increments to determine the proportion of individuals exceeding each benchmark at a given size. Uncertainty in these size-specific risk estimates was preserved by comparing the bounds of a 95 percent prediction interval for each fitted value to the benchmarks. The resulting size-specific risk profiles present changes in the risk of Hg across the size of individuals sampled from a population and can be used to identify the size at which a given proportion of individuals in a population likely exceed a specified threshold, or conversely, the proportion of individuals in a population that exceed a threshold at a given size. Because Hg concentrations in fish, and thus the risk of Hg to fish, wildlife, and humans, varies with fish size, these size-specific risk profiles better approximate the range of risks present in a population and provide important insights into how risks can be managed.

Results

Over a 4 year time span (2008, 2009, 2011, and 2012), we sampled 1,486 fish representing 16 different species from 86 individual sites across 21 national parks (table 1). Throughout all parks and species, fish muscle THg concentrations ranged over two orders of magnitude from 9.9 to 1,109 ng/g ww. The overall geometric mean (95-percent confidence interval in parentheses) of all fish sampled was 77.7 (73.6–80.8) ng/g ww. However, fish THg concentrations varied substantially among individual parks, with park-specific geometric mean values ranging from 32.6 (28.3–37.6) ng/g ww in Grand Teton NP to 325.6 (281.4–376.9) ng/g ww in Capitol Reef NP (table 2; fig. 2). Furthermore, within parks there was considerable variation in geometric mean fish THg concentrations among sites (table 3, figs. 2 and 3). The greatest range in site-specific geometric mean fish THg concentrations within parks occurred in Mount Rainier and Rocky Mountain NPs, where we measured approximately 11- and 8-fold differences, respectively, between the sites within each park with the lowest and highest THg concentrations (table 2, fig. 3). Importantly, the species and size distribution of fishes differed among parks and lakes, confounding direct comparisons across locations because of the influence that these factors have on THg concentrations (fig. 3). Therefore, we subsequently normalized the THg concentrations to account for the effects of size and species on fish THg concentrations, thus allowing for more meaningful spatial comparisons.

Model-Adjusted Mercury Concentrations

Inter-Park Comparisons

In order to control for the influence of size and species on fish Hg concentrations, we first assessed the relationships between fish length and THg concentrations on a site and species-specific basis as described in section, "Methods." Size was correlated with THg concentrations in 61 of the 104 site-species combinations (table 1; Significant Size Regression). For those 61 combinations, we normalized each individual THg concentration to a standardized length (50, 200, or 400 mm SL), which was dependent on the taxonomic grouping to which it was assigned (see section, "Methods"). For the site-species combinations where there were no relationships between length and Hg concentrations, we used unadjusted Hg values for each fish as it was assigned to its respective size category (table 1).

After accounting for the effects of size and species, LSM THg concentrations of each fish size class differed among parks (50 mm SL: $F_{3,107} = 100.15$, $p < 0.001$; 200 mm SL: $F_{14,56.7} = 79.60$, $p < 0.001$; 400 mm SL: $F_{4,124} = 79.08$, $p < 0.001$; fig. 4). Fish species assigned to the 400 mm SL size class only occurred in 5 of the 21 parks, primarily the northernmost parks—Denali, Wrangell-St. Elias, Lake Clark, Glacier, and Yellowstone NPs. Among those five parks, LSM THg concentrations in fish ranged from 47.4 ± 1.6 to 278.9 ± 7.4 ng/g ww. Fish THg concentrations were highest at Wrangell-St. Elias NP followed by Glacier, Lake Clark, Yellowstone, and Denali NPs (table 2, figs. 4 and 5).

Fish assigned to the 200 mm SL size class were collected from the greatest number of parks, and representatives of this size class are absent only from Denali, Lake Clark, Glacier, Capitol Reef, Zion, and Mesa Verde NPs. Mercury concentrations in fish from the 200 mm SL size class had a much narrower range of LSMs across parks than the 400 mm SL fish with concentrations ranging from 26.6 ± 2.6 to 119.9 ± 10.2 ng/g ww. Within this size class, Yellowstone NP had the highest fish THg concentrations, followed by Olympic, Glacier Bay, Grand Canyon, Wrangell-St. Elias, North Cascades, Yosemite, Sequoia-Kings Canyon, Lassen Volcanic, Great Sand Dunes, Mount Rainier, Rocky Mountain, Great Basin, Grand Teton, and Crater Lake NPs (fig 4, table 2).

Similar to the largest size class of fishes, we only collected samples falling into our smallest size class of fishes (50 mm SL) from a limited subset of four parks, mostly in the Southwestern region. Least-square mean THg concentrations in this size class ranged from 74.9 ± 2.9 to 242.5 ± 5.4 among parks. Among the 50 mm SL size class, fish Hg concentrations were highest at Zion NP, followed by Capitol Reef, Mount Rainier, and Mesa Verde NPs. The LSM values of 50 mm SL fish from Zion and Capitol Reef NPs are comparable to those in parks with the highest 400 mm SL fish (figs. 4 and 5).

Intra-Park Comparisons

In addition to regional differences in THg concentrations across parks, we also found differences in fish THg concentrations among sites nested within parks for each of the three size classes (50 mm SL: $F_{5, 107} = 12.22$, $p < 0.001$; 200 mm SL: $F_{57, 679.9} = 41.72$, $p < 0.001$; 400 mm SL: $F_{3, 124} = 31.56$, $p < 0.001$; fig 6, table 3). The magnitude of site differences within a park varied among parks and size classes. For the 400 mm SL size class, there were only two parks with multiple sites containing fish assigned to this size class. The sites with the highest THg concentrations were 1.33- and 3.35-fold higher than the sites with the lowest THg concentrations for Wrangell-St. Elias and Lake Clark NPs, respectively. For the 200 mm SL size class, the highest site within a park averaged 4.4 times higher than the lowest site within a park. The differences between the highest and lowest sites within parks ranged

from 1.27- to 22.61-fold in Great Basin and Mount Rainier NPs, respectively. For the 50 mm SL size class, the highest site within a park was on average 1.7 times higher than the lowest site within a park, and this difference between highest and lowest sites within a park ranged from 1.05- to 2.25-fold in Zion and Mount Rainier NPs, respectively. The values above provide insight into the overall range in concentrations within and among NPs, but do not adequately address the overall variance that was measured at each scale.

Variation Across Spatial Scales

To evaluate whether variation in fish THg concentration was most prevalent at the site, park, or regional level, we examined the CV at three scales: (1) CV among fish within individual sites, (2) CV among lakes within individual parks, and (3) CV among parks across the .Western United States, including Alaska. The CV among fish within individual sites ranged from 0.097 at Death Canyon Creek in Grand Teton NP to 0.819 at The Loch in Rocky Mountain NP, and averaged 0.303 across all sites (table 3). The CV among lakes within individual parks ranged from 0.121 in Great Basin NP to 0.865 on Yosemite NP (table 3). The mean CV among sites within parks (0.493) was greater than the average CV among fish within sites ($t = 3.87$, $df = 18$, $p = 0.001$). The CV among parks was 0.673 (table 3); significantly higher than the mean CV among sites within parks ($t = -3.798$, $df = 16$, $p = 0.002$). These data suggest that variation in THg concentrations increases at progressively larger landscape scales, with the greatest variation resulting from regional factors, followed by local and within-lake biological factors.

Inter-Annual Variation

There were no consistent patterns in inter-annual variability across the 10 sites sampled over separate years. Significant differences in mean Hg concentrations were observed at 5 of 10 sites. Fish THg concentrations increased from the first sampling year to the second at two sites: Sun Up Lake (Olympic NP; $F_{1,27} = 6.35$, $p = 0.018$; fig. 7) and Center Basin Lake (Sequoia-Kings Canyon NP; $F_{1,42} = 22.87$, $p < 0.0001$; fig. 7). Conversely, fish THg concentrations decreased from the first sampling event to the second in three sites—Upper Lena Lake (Olympic NP; $F_{1,24} = 7.12$, $p = 0.014$, fig. 7), Poudre Lake (Rocky Mountain NP; $F_{1,27} = 4.77$, $p = 0.038$, fig. 7), and Ypsilon Lake (Rocky Mountain NP; $F_{1,27} = 4.36$, $p = 0.046$, fig. 7). Finally, we found no differences among years at the remaining five sites—Gladys Lake (Olympic NP; $F_{1,26} = 1.13$, $p = 0.30$), Lake Nanita (Rocky Mountain NP; $F_{1,20} = 0.004$, $p = 0.89$), Mirror Lake (Rocky Mountain NP; $F_{1,27} = 0.21$, $p = 0.65$), Kern Point (Sequoia-Kings Canyon NP; $F_{1,27} = 1.47$, $p = 0.23$), and Lake Clark (Lake Clark NP; $F_{1,24} = 0.037$, $p = 0.85$). The magnitude of differences between years was 19.6 percent in Sun Up Lake (Olympic NP), 24.4 percent in Ypsilon Lake (Rocky Mountain NP), 24.8 percent in Upper Lena Lake (Olympic NP), 26.5 percent in Poudre Lake (Rocky Mountain NP), and 43.6 percent in Center Basin Lake (Sequoia-Kings Canyon NP).

Toxicological Risk

Estimating toxicological risk of Hg within ecosystems can be subjective and dependent on the endpoints selected, the uncertainty surrounding individual- and species-specific sensitivity estimates, and whether risk is based on dietary exposure or tissue-based Hg concentrations. Because of the geographic scale of this study, the wide range of species sampled, and the somewhat limited sample sizes within sites, we evaluated ecological and human health risk at a relatively coarse scale, by comparing measured, unadjusted fish THg concentrations to a gradient of pre-established benchmarks

individually for fish health, avian (piscivorous bird) health, and human health. However, in addition to simply comparing the proportion of sampled fish to these thresholds, we modeled Hg risk to each group across the range of fish sizes for each site in order to evaluate how risk to these groups varies with fish size (fig. 8; see section, “Methods”).

Fish Risk

Across all parks, species, and sizes of fish, 5 percent of individuals had whole-body THg concentrations above which Hg exposure may affect fish health (NOER; 200 ng/g ww; table 4). Fewer than 2 percent of individuals had whole-body THg concentrations above which deleterious effects are likely (LOER; 300 ng/g ww; table 4).

The distribution of risk was not evenly distributed across all parks. Thirteen of the 21 parks sampled contained no fish exceeding the 200 ng/g NOER benchmark. In the eight parks (38 percent) with fish exceeding 200 ng/g THg, the proportion of individual fish exceeding this benchmark was highest in Capitol Reef NP, where 49 percent of fish sampled had concentrations above 200 ng/g ww, followed by Lake Clark, Zion, Wrangell-St. Elias, Yosemite, Lassen Volcanic, Rocky Mountain, and Mount Rainier NPs (table 4). Of the 21 parks sampled, only 6 (Capitol Reef, Lake Clark, Wrangell-St. Elias, Zion, Yosemite, and Rocky Mountain NPs; 29 percent) contained fish with THg concentrations exceeding the 300 ng/g ww LOER benchmark (table 4), the value above which deleterious effects to fish are likely. Twenty-two percent of fish from Capitol Reef NP exceeded this concentration, whereas Lake Clark, Wrangell-St. Elias, Zion, Yosemite, and Rocky Mountain NPs had progressively lower proportions fish exceeding this benchmark (table 4).

When examined on a site-specific basis, fish THg concentrations exceeded 200 ng/g ww in 13 sites (15 percent) across the 8 parks containing fish with values above this benchmark. More than one-half of the individual fish exceeded the NOER threshold at Tanada Lake (85 percent) in Wrangell-St. Elias NP, Fremont River site 1 (67 percent) and site 7 (60 percent) in Capitol Reef NP, and Lake Clark (54 percent) in Lake Clark NP (table 4). Other sites with fish exceeding the NOER benchmark include East Fork Virgin River (Zion NP), MORA_1614 (Mount Rainier NP), Fremont River site 4 (Capitol Reef NP), Lake Kontrashibuna (Lake Clark), Mildred Lake (Yosemite NP), Fall River (Rocky Mountain NP), Mirror Lake (Rocky Mountain NP), North Fork Virgin River (Zion NP), Horseshoe Lake (Lassen Volcanic NP). The 300 ng/g LOER was exceeded in only 8 individual sites (9 percent). Two sites in Capitol Reef NP (Fremont River sites 1 and 7) had the highest proportions of individuals exceeding this benchmark, 33 and 27 percent, respectively (table 4). Other sites with fish exceeding the LOER benchmark include Tanada Lake (Wrangell-St. Elias NP), Lake Clark (Lake Clark NP), Fremont River site 4 (Capitol Reef NP), Mildred Lake (Yosemite NP), North Fork Virgin River (Zion NP), and Fall River (Rocky Mountain NP).

Size-Specific Risk

We modeled risk across the observed size range for all 61 populations with size-Hg relationships. This approach was implemented so that instead of simply calculating the proportion of fish exceeding benchmarks from the sampled size range (which is not necessarily representative of the size distribution of fish within the lake), we could estimate specific lengths at which most fish exceed each benchmark. Taking this approach, our models estimated that fish would exceed the 200 ng/g ww NOER benchmark in 21 (34 percent) of the populations modeled (fig. 9). In eight of those populations, at least one-half of all individuals are predicted to exceed the NOER at some length along their size spectra (fig. 9). Four of these populations were speckled dace from three sites in Capitol Reef NP and one site in Zion NP. In these four populations, the mean size at which 50 percent of the individuals were

modeled to exceed the benchmark was 61 mm SL, ranging from 52 mm SL in Capitol Reef's Fremont River site 1, to 67 mm SL in Fremont River sites 4 and 7 (fig. 9). For the other four populations, our models predict that 50 percent of the individuals will exceed the NOER at 264 and 302 mm in brook trout from Mildred Lake in Yosemite NP and Horseshoe Lake in Lassen Volcanic NP, respectively, 323 mm SL in suckers from Fall River in Rocky Mountain NP, and 412 mm SL in lake trout from Tanada Lake in Wrangell-St. Elias NP (fig. 9).

Model predictions estimate that fewer fish populations (12 of 61 populations modeled; 20 percent) are expected to contain individuals exceeding the 300 ng/g LOER over the range of fish sizes sampled in each population than estimated for the NOER (fig. 9). At least 50 percent of the individuals in five of the populations were predicted to exceed this benchmark at some point within their measured size spectra. Four of those populations were specked dace from Capitol Reef and Zion NPs, where the estimated size at which 50 percent exceeded the benchmark was 71 mm SL (fig. 9). Additionally, at least one-half of the lake trout population greater than 526 mm SL from Tanada Lake in Wrangell-St. Elias NP are projected to exceed the LOER (fig. 9).

Avian Risk

When examining the unadjusted whole-body THg concentrations, 35 percent of all fishes sampled had THg concentrations above our benchmark for risk to birds with high sensitivity to Hg exposure (90 ng/g ww; table 4). Tissue concentrations in 12 percent of individual fish exceeded the 180 ng/g ww benchmark for reproductive impairment in species with moderate sensitivity, and 5 percent of individual fish exceeded 270 ng/g ww, our benchmark for risk to birds with low sensitivity to Hg exposure (table 4).

Among the 21 parks, the potential risk to piscivorous birds varied substantially. In 7 parks (33 percent), none of the fish analyzed exceeded the 90 ng/g ww benchmark for highly sensitive bird species. In the remaining 14 parks (67 percent), more than one-half of sampled fish were above this concentration, and more than three-quarters of sampled fish exceeded this value in Lake Clark, Zion, Capitol Reef, and Glacier NPs (76, 90, 98, and 100 percent, respectively). The benchmark for reproductive impairment in moderately sensitive avian species was exceeded in nine (43 percent) parks. The proportion of fish within these nine parks that exceeded this benchmark, ranged from 1 percent of individual fish at Yellowstone NP to 56 percent of individual fish at Capitol Reef NP, which was the only park from which more than one-half of the fish sampled exceeded the moderate sensitivity benchmark (table 4). Fourteen of the 21 parks had no fish with THg concentrations above the benchmark for birds with low Hg sensitivity (table 4), and the proportion of fish exceeding this threshold was less than 10 percent in all remaining seven parks (33 percent) except Capitol Reef, where 33 percent of fish sampled exceeded the threshold (table 4).

On a site-specific level, 41 of the 86 sites sampled had no fish with THg concentrations above the benchmark for the most sensitive avian species (table 4). However, at the remaining 45 sites (52 percent), 63 percent of fish exceeded this benchmark, and at 7 sites, 100 percent of fish sampled were above the high sensitivity avian benchmark. At an additional seven sites, between 50 and 93 percent of fish had THg concentrations greater than the high sensitivity avian threshold (table 4). The loon reproductive impairment threshold was exceeded at 18 sites (21 percent), with more than one-half of the fish surpassing this benchmark at four sites (table 4). Nine individual sites (representing seven parks) contained fish with THg concentrations above the benchmark for birds with low sensitivity to Hg (table 4).

Size-Specific Risk

Size-specific Hg risk to piscivorous birds was modeled for 61 populations. Of these, whole-body Hg concentrations in fish from 14 populations (23 percent) did not exceed the 90 ng/g ww benchmark for risk to the most sensitive avian species, while the remaining 47 populations (77 percent) were modeled to exceed this threshold at some size (fig. 10). However, 100 percent of lake trout from Tanada and Copper Lakes in Wrangell-St. Elias NP and lake whitefish from Lake McDonald in Glacier NP were predicted to exceed this benchmark over the entire range of fish sizes (fig. 10). The size at which 50 percent of the fish in a population were predicted to exceed the benchmark for risk to highly sensitive piscivorous birds ranged from less than 40 mm SL in speckled dace from Fremont River site 1 in Capitol Reef NP to 414 mm SL in brown trout from the Colorado River in Rocky Mountain NP. Among the smaller "forage fish" (that is, speckled dace, torrent sculpin, and threespine stickleback), the mean size at which 50 percent of the individuals within a population exceeded the threshold was 59 mm SL (n = 6 populations). For brook trout, cutthroat trout, and rainbow trout, the mean size at which 50 percent of the individuals within a population exceeded the threshold was 223 mm SL (n = 15 populations).

The majority of individual populations modeled (36 of 61 populations, 59 percent) were predicted to have no individual fish with THg concentrations exceeding the benchmark for reproductive impairment in moderately sensitive avian consumers across the range of fish lengths, whereas in 25 parks (41 percent), some fish were modeled to exceed this benchmark (fig. 10). However, in 10 populations, more than one-half of the individual fish in each population were predicted to have THg concentrations above the common loon reproductive impairment benchmark, and lake trout from Tanada Lake in Wrangell-St. Elias NP were modeled to exceed this threshold over the entire range of sizes sampled (fig. 10). Four of the 10 populations with greater than 50 percent of fish predicted to exceed the loon risk concentration at some length within the population were speckled dace. The mean size at which 50 percent of these speckled dace populations was predicted to exceed the loon risk benchmark is 58 mm SL. The mean size at which 50 percent of the individuals in a population was modeled to exceed the loon risk threshold was 261 mm SL for three brook trout populations (Horseshoe Lake in Lassen Volcanic NP, Mirror Lake in Rocky Mountain NP, and Mildred Lake in Yosemite NP).

Our models predicted that fish from 12 populations sampled (20 percent) would exceed the 270 ng/g ww threshold for birds with the lowest Hg sensitivity at some point along their size spectrum (fig. 10). In six of the populations, 50 percent or more of the individuals were modeled to exceed this threshold at some size. Four of these six populations were speckled dace from Capitol Reef and Zion NPs, and the mean length at which 50 percent of the population was predicted to exceed the threshold was 68 mm SL, only 10 mm greater than the same exceedance level for loon risk. The other two populations were suckers from the Fall River in Rocky Mountain NP and lake trout from Tanada Lake in Wrangell-St. Elias NP. In those populations, the model-predicted size at which 50 percent of the population exceeded the threshold was 353 and 496 mm SL, respectively.

Human Consumption Risk

As mentioned in section, "Methods," human health risk was assessed using fish muscle THg concentrations, not whole-body concentrations as was done for wildlife risk. In the unadjusted data across all parks, species and sizes of fish, 32 percent of fish sampled had THg concentrations in their muscle below the 50 ng/g ww threshold established by the GLAG for unlimited consumption of fish, indicating that some human consumption guidance would apply to 68 percent of the individuals measured in this study (table 4). However, only 4 percent of fish had muscle THg concentrations exceeding the EPA human health criterion of 300 ng/g ww, and less than 1 percent had concentrations above the level at which GLAG recommends that no fish be consumed (950 ng/g ww).

As with the other benchmarks, the proportion of fish exceeding human risk thresholds varied greatly among parks. Grand Teton and Great Basin NPs had the lowest proportion of fish exceeding the GLAG unlimited consumption threshold (18 percent), whereas 100 percent of fish analyzed from Glacier NP exceeded this threshold (table 4). In 17 parks (81 percent), more than one-half of sampled fish had concentrations above the GLAG threshold. In 11 (61 percent) of the 18 parks from which species consumed by humans (that is, excluding speckled dace, threespine stickleback, and torrent sculpin) were analyzed, no fish had muscle THg concentrations exceeding the EPA human health criterion. In the remaining 7 of 18 parks (39 percent) with fish exceeding the EPA human health criterion, the proportion of fish with concentrations above 300 ng/g ww was typically only 1–3 percent of individuals, with the exception of Lake Clark, Wrangell-St. Elias, and Yosemite NPs, where 40.7, 18.3, and 6.7 percent of fish exceeded the guideline, respectively (table 4). Yosemite was the only park in which any fish exceeded the GLAG no consumption guideline, with 3 percent of the analyzed fish having muscle concentrations over the guideline (table 4).

When examined at the finer site scale, 6 (8 percent) of the 79 sites from which fish species consumed by humans were sampled had no fish exceeding the GLAG unlimited consumption guideline, whereas at 23 of these sites (30 percent) all fish analyzed exceeded this guideline. At 56 sites (71 percent) at least 50 percent of the fish analyzed exceeded the unlimited consumption guideline. Thirteen sites (17 percent) had fish exceeding the EPA human health criterion, with more than 50 percent of individual fish from Lake Clark (80 percent) in Lake Clark NP and Tanada Lake (85 percent) in Wrangell–St. Elias NP exceeding the guideline. Mildred Lake in Yosemite NP was the only lake from which fish (7 percent) exceeded the GLAG no consumption guideline.

Size-Specific Risk

We used the same approach presented for fish and birds to model risk to humans across the size spectra of 54 populations with size-THg relationships. These models predicted that muscle THg concentrations in fish from every population would exceed the GLAG unlimited consumption guideline at some length over the observed range of sizes (fig. 11). The sole exception was cutthroat trout from Death Canyon Creek in Grand Teton NP, where even the largest fish sampled (260 mm SL) were predicted to have muscle concentrations below this level. In 40 of the 54 populations (74 percent) modeled, the unlimited consumption threshold was predicted to be exceeded by some fish across the entire range of observed sizes (fig. 11). In 8 populations (15 percent), all fish were expected to exceed this threshold across the entire range of sizes sampled. In the remaining populations, the average size at which 50 percent of the fish in a population were expected to exceed the threshold varied substantially, ranging from 40 mm SL in brook trout from Golden Lake in Mount Rainier NP to nearly 400 mm SL in northern pike from Lake Chilchukabena in Denali NP. When limited to brook, rainbow, and cutthroat trout, which comprise nearly 65 percent of the fish analyzed, the average size at which 50 percent of the fish in a population were modeled to exceed the unlimited consumption guideline was 179 mm SL (n = 36 populations).

Eighteen populations were modeled to exceed the EPA criterion for human consumption at some point across the measured size spectra (fig. 11). In six of these populations, models estimated that 50 percent or more of the individual fish at a certain size threshold within a population were predicted to exceed the EPA human health criterion, and all lake trout down to the smallest size (410 mm SL) from

Tanada Lake in Wrangell-St. Elias NP were predicted to exceed the EPA human health criterion (fig. 11). For the three brook trout populations where at least one-half of the fish at a given size were predicted to exceed the EPA criterion (Horseshoe Lake in Lassen Volcanic, Golden Lake in Mount Rainier, and Mildred Lake in Yosemite), the average size at which 50 percent of the individuals exceeded it was 258 mm SL.

After modeling risk across the entire sampled fish size range, nine populations (17 percent of all populations) are predicted to include some fish that exceed the GLAG no consumption guideline (fig. 11). Of these nine populations, the models predicted that only two populations (suckers from the Fall River in Rocky Mountain NP and brook trout from Mildred Lake in Yosemite NP) were expected to have more than 50 percent of individuals in the population exceeding the threshold at some length along the size spectra for each population. The sizes at which 50 percent of individuals exceeded this threshold were 353 and 250 mm SL in suckers from the Fall River and Mildred Lake, respectively (fig. 11).

Discussion

Our results indicate that Hg bioaccumulation and risk to aquatic ecosystems of national parks in the Western United States is widespread, yet highly variable. Total Hg concentrations in individual fish ranged over two orders of magnitude across more than 1,400 individuals analyzed, with the lowest concentrations near 10 ng/g ww and the highest concentrations exceeding 1,100 ng/g ww. Importantly, this variation in Hg concentrations not only occurred across parks, but also among different sites within parks, even in light of site selection criteria that included restricting sites to mostly oligotrophic, headwater systems. These results highlight the significance of both local and regional-scale processes in determining Hg risk. As a result of this variability, many of the parks contained fish that were all below even the most conservative benchmarks of risk to fish (13 of 21 parks) and piscivorous birds (7 of 21 parks). Moreover, although all parks contained one or more fish that exceeded the GLAG unlimited consumption benchmark, most parks (14 of 21) did not have any fish in exceedance of the 300 ng/g ww EPA fish tissue criterion. Conversely, for those parks with fish that did exceed ecological and human health benchmarks, a substantial proportion of the fish had concentrations that were above those thresholds of concern. This was particularly true in the case of avian risk, where more than one-half of the fish sampled in several locations exceeded thresholds for risk to reproductive impairment in highly sensitive and moderately sensitive bird species. Although we did not directly assess risk to mammalian wildlife, the benchmarks chosen for avian consumers correspond closely with the no-observed-affect-level (NOAEL) benchmark for dietary Hg in mammalian wildlife (110 ng/g ww; Basu and Head 2010). Thus, our data suggest that mammalian wildlife also are likely to be at risk across these parks. Finally, although the geographic distributions in species occurrence impeded direct comparisons across all parks simultaneously, our data identify two regions of particular concern—(1) some parks in Alaska, as well as Glacier NP, had THg concentrations in large top predator fish species that approached or exceeded human consumption guidelines, and (2) some of the smallest “forage fish” sampled in the arid Southwest region had among the highest THg concentrations of the entire study, greatly exceeding wildlife risk thresholds for reproductive impairment. Although many plausible explanations exist for these patterns, investigating the potential mechanisms was beyond the scope of this study. Thus, more work is needed to better understand the landscape drivers of THg concentrations in these fish, as well as any deleterious effects these Hg concentrations might be having on resident biota in these parks. Additionally, information regarding the species composition, size ranges, and consumption rates of fish consumed by subsistence fishers in Alaskan parks is important for better characterizing human health risk in those parks.

THg concentrations in fish from this study generally are consistent with those of other studies in freshwater habitats of protected lands in the Western United States. For example, the Western Airborne Contaminants Assessment Project (WACAP) measured fish THg concentrations in 14 lakes from eight western national parks, six of which also were included in this study (Landers and others, 2008). Mean whole-body concentrations ranged from less than 40 ng/g ww in Glacier NP to slightly more than 200 ng/g ww in Noatak NP, Alaska (Landers and others, 2008). However, because the WACAP study was designed specifically as a screening study, there was limited replication within parks for evaluating site-specific variability in relation to regional variability. The need for such replication is indicated by a comparison of Hg concentrations reported from Glacier NP by Landers and others (2008) and the current study. Landers and others (2008) found Hg concentrations in cutthroat trout from two lakes in Glacier NP to be among the lowest measured in their study, whereas in the current study, concentrations from a third lake in Glacier were among the highest observed.

We specifically addressed this issue by sampling two parks (Mount Rainier and Rocky Mountain) intensively, with 17 and 19 different sites in each park, respectively. This higher resolution sampling revealed up to 20-fold variation in size-normalized fish THg concentrations among lakes within an individual park. This level of variation within a park is important to demonstrate and incorporate into park-level assessments, but is not unexpected given the well-established linkages between site-level characteristics and both methylation and bioaccumulation processes (Hall and others, 2008; Mitchell and Gilmour, 2008; Gabriel and others, 2009; Rolfhus and others, 2011; Hsu-Kim and others, 2013). Regardless, relatively little information exists about this variability in remote and high-altitude habitats that were the focus of this study. Recent studies do suggest that Hg bioaccumulation in osprey nesting in alpine habitats is regulated by a combination of local processes and atmospheric deposition (Guigueno and others, 2012). Similarly, Hg loadings to western Canadian alpine lakes was most strongly related to site-specific processes such as organic matter supply and catchment weathering (Phillips and others, 2011). Moreover, a recent study of THg concentrations in fish from sub-alpine lakes in the Wallowa-Whitman National Forest in northeastern Oregon and western Idaho focused on among-lake variation in fish THg concentrations within a relatively localized (Eagles-Smith and others, 2013). Consistent with the current study, mean fish THg concentrations among lakes varied by more than an order of magnitude (25–443 ng/g ww), even though all lakes were within 100 km of one another. Conifer density (basal area) within the catchment of each lake was the strongest predictor of fish THg concentrations among lakes (Eagles-Smith and others, 2013), highlighting the importance of watershed characteristics on downstream Hg cycling processes. At an even broader scale, the percentage of land covered by coniferous forests (coupled with wet Hg deposition) across six States in the south-central U.S. was an important factor influencing fish THg concentrations (Drenner and others, 2013). The hierarchical spatial design of the current study, combined with the gradient in landscape types, altitudes, and fish species that occur over the approximately 4,000 km distance, complicate a similar landscape scale analysis without even greater data density and replication among sites. However, our results support the notion that Hg risk is driven by a dynamic balance of local, regional, and global processes. What is unclear, is how the relative importance of these processes changes across locations, which should be addressed in focused future research in order to facilitate more informed management of Hg risk.

Although we do not formally address risk to the unique ecological communities across the parks studied, the model-adjusted fish THg concentrations provide a valuable index of relative risk to fish, wildlife, and human health. Our results suggest that although risk is low in many locations, there are substantial concerns about the impact of Hg on ecological health in other locations. In particular, THg concentrations in speckled dace, a small invertebrate-foraging minnow from Zion and Capitol Reef NPs,

commonly exceeded some of the highest values in top predators, such as lake trout, from other parks. Size-normalized (50 mm) mean THg concentrations in these fish exceeded 200 ng/g ww in both parks, and mean concentrations in one site exceeded 300 ng/g ww. Moreover, across the range of fish sampled in these parks (approximately 70–100 mm SL), most fish exceeded these values. Because speckled dace occupy intermediate trophic positions, they serve as potential prey items for predatory fish and piscivorous birds, and dietary Hg concentrations at these levels are associated with biochemical and reproductive effects in fish (Depew and others, 2012a), as well as reproductive impairment in birds (Depew and others, 2012b). Moreover, it suggests that other invertebrate-feeding organisms in the park could be at risk. Amphibians and riparian- or aquatic invertebrate-feeding birds are two groups in particular that are both sensitive to Hg, and likely to be exposed due to their foraging ecology (Bergeron and others, 2011a, 2011b; Jackson and others, 2011; Metts and others, 2012; Willson and Hopkins, 2013).

THg concentrations in fish from Wrangell-St. Elias, Lake Clark, and Glacier NPs approached or exceeded all three benchmarks associated with reproductive impairment in piscivorous birds (90, 180, and 270 ng/g ww), and the EPA criterion for protection of human health. It is unclear whether these elevated concentrations are the result of enhanced MeHg production in these systems, or simply the fact that these were large fish (400–650 mm SL) that were likely many years old and had reached a growth asymptote in systems with only moderate Hg availability. This information gap is an important component to address with future work because it will help better gauge risk to park visitors and wildlife. Both Wrangell-St. Elias and Lake Clark support subsistence hunting and fishing activities for native and non-native rural Alaskans. If toxicological risk is mostly restricted to large, older fish, then guidelines can be better established to inform subsistence users of how to minimize exposure risk. Moreover, relatively few wildlife species are capable of consuming these large individuals, suggesting fewer species would be at risk from fish consumption and the species that are would likely be more easily monitored. Thus, understanding the relative risk posed across the size spectra of a population provides important insights into how that risk can be monitored and managed. Conversely, if certain habitats or locations within these parks are particularly sensitive to Hg methylation, the food web contamination may be more widespread, potentially necessitating a broader communication and monitoring strategy that might incorporate a more comprehensive array of subsistence foods and other wildlife taxa. Progress is already being made to address this potential concern, and USGS and Wrangell-St. Elias NP are currently completing a study to assess THg concentrations in several additional locations and species, as well as to evaluate the age structure of the fish being sampled. Although subsistence harvest is not a concern in Glacier NP, one of the species we measured, the bull trout, is listed as federally threatened under the endangered species act. Hg concentrations that we measured in bull trout from Lake McDonald in Glacier NP approached levels of concern for tissue-based fish toxicity. Because we only sampled fish from a single lake in Glacier NP, it is unclear if this is a widespread concern for toxicity to bull trout or their predators, but our data suggest that a follow-up study is warranted.

The unprecedented spatial breadth of this study facilitates the most thorough understanding of Hg bioaccumulation patterns in fish of western national parks to date. Our analysis and data compilation provide novel insight into the broad-scale distribution of Hg in fish communities of remote, protected habitats. Of note, many locations show limited Hg risk, and our data confirm that even with continued

increases in global Hg releases (Sunderland and Selin, 2013), many protected NPS lands in the United States still exhibit relatively low Hg risk. However, our results also raise new questions and can be used to guide the development of future research to help manage the unexpected number of locations in this study where Hg contamination could be an ongoing or emerging threat to ecosystem health. The high degree of variation within parks and that the parks with the most intensive sampling had the greatest range in THg concentrations. These findings strongly suggest that more intensive research and monitoring efforts within parks will undoubtedly reveal both low and high risk environments. Thus, monitoring programs should not focus on a small number of "indicator" sites and we recommend that where feasible, newly established monitoring or investigation efforts focus on sampling at the largest spatial scale possible within a park to better understand this variability.

Additionally, our focus on high-altitude habitats provided little insight regarding the magnitude of risk in lower altitude lakes and wetlands. Recent work in Mount Rainier NP suggests that Hg bioaccumulation in wetlands and lakes is substantially higher in the lowest-altitude habitats (C.A. Eagles-Smith, U.S. Geological Survey, unpub. data, 2013). Additional monitoring in low-altitude habitats that integrate a broader range of watershed processes is warranted.

Beyond monitoring, a more quantitative understanding of the biogeochemical and food web factors that regulate within-park variability will facilitate greater certainty in predicting areas across these parks with the greatest risk likelihood. Future interdisciplinary research across a range of replicated aquatic habitat types that couples key biogeochemical process-level measurements with detailed food web processes and quantification of bioaccumulation pathways would provide valuable insight for developing these predictive models. A new collaborative, citizen-science effort between USGS, NPS, and University of Maine will make initial progress in this area by evaluating Hg bioaccumulation in biosentinel dragonfly larvae in relation to a range of biogeochemical and landscape drivers. One benefit of this upcoming effort is that the use of dragonflies as biosentinels will inform the parks about risk to aquatic habitats that are not fish-bearing. Another impending contribution in this realm will be provided by an empirical model being developed by the USGS Mercury Research Laboratory that will predict aqueous MeHg concentrations in surface water based on water chemistry and watershed structure. Coupling this model with biological assessments may provide more predictive power to assess ecological risk.

Although these suggestions will greatly increase the understanding of the drivers of Hg cycling in national parks, estimates of risk will continue to be speculative and of limited confidence without empirical research on toxicological responses in resident park biota. This lack of robust toxicological benchmarks for many taxa was a particular concern in the current study because few taxa extended across the large spatial extent and ecologically diverse habitats sampled. Although our choice of toxicological benchmarks were appropriate given the constraints of the current study, generalized benchmarks, such as our bird risk thresholds, do not provide definitive estimates of risk to specific park resources. Specifically, the data presented here suggest that toxicological assessments of key ecological endpoints in Capitol Reef, Zion, Lassen Volcanic, Yosemite, Wrangell-St. Elias, Lake Clark, and Glacier NPs are warranted. Direct assessments of the physiological, behavioral, and reproductive responses of wildlife and fish in these parks will be tremendously valuable for calibrating risk estimates that have been derived on different taxa in unrelated habitats, and provide a baseline from which meaningful benchmarks for evaluating the integrative risk of Hg toxicity to whole parks or ecosystems could be developed.

National Park Summaries

Capitol Reef National Park

All fish sampled from Capitol Reef NP were speckled dace, a small insectivorous "forage fish." Despite their intermediate position in the food web, these fish contained some of the highest Hg concentrations measured in this study, exceeding those measured in many of the largest predatory fish. As smaller fish, speckled dace serve as potential prey items for predatory fishes and piscivorous birds, and dietary Hg concentrations at these levels are associated with biochemical and reproductive effects in fish (Depew and others, 2012a), as well as reproductive impairment in birds (Depew and others, 2012b). Moreover, such high Hg concentrations suggest that other invertebrate-feeding organisms in the park could be at risk. Amphibians and riparian- or aquatic invertebrate-feeding birds are two groups in particular that are both sensitive to Hg, and likely to be exposed due to their foraging ecology (Bergeron and others, 2011a, 2011b; Jackson and others, 2011; Metts and others, 2012; Willson and Hopkins, 2013). However, we only sampled a single species at three sites in Capitol Reef NP, all of which were along the Freemont River. Therefore, we are unable to speculate whether the fish communities throughout the park contain similarly high concentrations, or whether these values were the result of a localized process. Future sampling of additional sites and species within the park is necessary to fill this important knowledge gap.

Crater Lake National Park

Kokanee and rainbow trout were sampled from two sites in Crater Lake NP. The two species had similar Hg concentrations and were among the lowest measured in this study, ranging from 16.8 to 76.0 ng/g ww. Overall our results indicate that Hg concentrations in fish from Crater Lake are unlikely to put fish or avian consumers at risk.

Denali National Park

We sampled northern pike from a single lake in Denali NP. Despite their large size and position as top predators, northern pike from Denali NP had the lowest size-normalized Hg concentrations in the 400 mm SL size class (47.4 ng/g ww at 400 mm SL) and some of the lowest observed in the entire study. In fact, the THg concentrations in northern pike from Denali were similar or less than THg concentrations in smaller fish species from the other parks in Alaska (Wrangell-St. Elias, Lake Clark, Glacier Bay). Moreover, past work in Denali found similarly low THg concentrations in burbot (*Lota lota*) and whitefish (Landers and others, 2008). Such low Hg concentrations may be the result of this site's isolated nature. However, at other similarly isolated sites in Alaska, northern pike have been found to have consistently higher Hg concentrations (110–1,500 ng/g ww on average; Jewett and Duffy, 2007). Any additional sampling from Denali NP should aim to assess whether these data are representative of other water bodies and species in the park.

Glacier Bay National Park

We sampled Dolly Varden from two lakes and one stream in Glacier Bay NP. Mean THg concentrations across these three sites (90.2 ng/g ww) were slightly above the global mean concentration in fish across all sites and parks in this study (77.7 ng/g ww). When modeled at 200 mm, the mean Hg concentration in fish from Glacier Bay NP (102.3 ng/g ww) was among the highest in the size class. However, we also observed a 3-fold variation in the mean concentrations among the three lakes indicating that local processes are likely important drivers of Hg bioaccumulation in fish within this park. The THg concentrations measured in Dolly Varden from Glacier Bay NP were similar to concentrations (40–230 ng/g ww) found in Dolly Varden from other sites in Alaska (Jewett and Duffy, 2007).

Glacier National Park

Lake whitefish and bull trout were sampled from Lake McDonald in Glacier NP. Both species had high Hg concentrations relative to the mean across all fish in the study, and after accounting for the effects of size and species, fish from Glacier NP were some of the highest in the large (400 mm SL) size class. Mercury concentrations in Glacier NP fish approached or exceeded the EPA criterion for protection of human health and the level at which reproductive impairment to piscivorous birds could occur. Additionally, Hg concentrations in many individuals exceeded the level at which tissue-based toxicity to fish is a concern. This is particularly important considering bull trout is federally listed as threatened under the endangered species act. Because we only sampled fish from a single lake, we cannot assess whether these data are representative of other lakes in the park. However, Landers and others (2008) found that fish from two other lakes within Glacier NP had the lowest Hg concentrations among the 14 lakes measured across national parks in the West. These contrasting results suggest that substantial variation in Hg concentrations exists among water bodies within Glacier NP and more detailed analysis of local processes may be necessary to effectively manage risk.

Grand Canyon National Park

At the three sites we sampled in Grand Canyon NP, unadjusted mean THg concentrations (76 ng/g ww) were similar to the average across all fish in the study. However, size adjusted (200 mm SL) THg concentrations were among the highest in the size class (101.2 ng/g ww) across all parks. Moreover, size-adjusted THg concentrations in Shinumo Creek (178.8 ng/g ww) were more than 2-fold higher than those in the other two sites (71.5 and 81.0 ng/g ww), suggesting that Hg exposure within the park is variable.

Grand Teton National Park

Mercury concentrations in fish from the two lakes and one stream sampled in Grand Teton NP were consistently among the lowest measured in this study. It is unclear whether these low concentrations are the result of low local inputs of Hg, the Hg methylation potential of the water bodies measured, or some biological characteristic of the fish.

Great Basin National Park

We sampled brook trout from two creeks and a lake in Great Basin NP. Among these three sites Hg concentrations were uniformly among the lowest measured in the current study suggesting that at the time of sampling the ecological risk posed by Hg in these systems is likely low. Atmospheric dry deposition in Great Basin NP was among the highest measured in six western national parks (Wright and others, 2014).

Great Sand Dunes National Park

Mercury concentrations in fish from one of the two sites (Medano Lake; 70.1 ng/g ww) sampled in Great Sand Dunes NP were similar to the average across parks, whereas fish from the second site (Sand Creek; 52.7 ng/g ww) were considerably lower. Based on these data, the risk of Hg exposure to wildlife is likely low at these sites; however, data from these two sites may not adequately characterize risk at other locations within the park.

Lake Clark National Park

Lake trout from three lakes in Lake Clark NP were included in this study. Two of these sites (Lake Clark and Lake Kontrashibuna) were sampled in both 2011 and 2012, although Hg concentrations were not significantly different between the 2 years. Although THg concentrations across all sites within the park were among the highest observed in the 400 mm SL size class, there was considerable variation among lakes within the park. The mean THg concentration in Lake Clark (365.2 ng/g ww) was more than 3-fold higher than that in Telaquana Lake (109.0 ng/g ww) and 1.8 than that in Lake Kontrashibuna (204.0 ng/g ww). At the lower end of this range, THg concentrations pose limited risk to park wildlife and human users. However, the concentrations observed in Lake Kontrashibuna exceeded the benchmark for reproductive impairment to piscivorous birds, and the tissue-based criterion for fish toxicity. Moreover, fish from Lake Clark exceeded these benchmarks and the EPA criterion for protection of human health.

Lassen Volcanic National Park

There was greater than 4-fold variation in mean fish THg concentrations among the three lakes that brook trout were sampled from in Lassen Volcanic NP. Mercury concentrations were lowest in Summit Lake (43.7 ng/g ww), whereas Ridge Lake (111.3 ng/g w) and Horseshoe Lake (180.7 ng/g ww) had concentrations above the mean concentration for all fish in this study. Some of this variation in Hg concentrations among lakes in the park was due to the size of fish. After adjusting fish THg concentrations to a 200 mm SL fish size, the variation among lakes was substantially reduced. Size-based risk assessments were conducted for Horseshoe and Summit Lakes, and the resulting risk profiles contrast sharply. Our modeled risk estimates suggest that there is limited toxicological risk to fish, wildlife or humans across the fish size range in Summit Lake. Conversely, brook trout from Horseshoe Lake were modeled to reach concentrations of concern for tissue-based fish toxicity and risk to even the least sensitive species of avian consumers within the range of sizes sampled. Furthermore, a high proportion of fish from Horseshoe Lake were modeled to exceed the EPA criterion for protection of human health at sizes exceeding 280 mm SL.

Mesa Verde National Park

Speckled dace were sampled from a single location, the Mancos River, in Mesa Verde NP. Despite the small size of these fish (43–69 mm SL), their THg mean concentration (74.9 ng/g ww) was to the study-wide mean value. However, the THg concentrations from speckled dace from the lone site in Mesa Verde NP were much lower than those measured in dace from nearby Capitol Reef and Zion NPs. This difference suggests that the high concentrations observed in dace from these other parks is not solely due to some aspect of this species biology, but may reflect environmental processes occurring at the site or watershed scale.

Mount Rainer National Park

Mount Rainer NP is one of two parks in which we sampled a large number of sites in order to characterize intra-park variation. Although the average fish THg concentration across the 17 sites from which fish were sampled (71.5 ng/g ww) was similar to the study-wide mean across all fish, we found a 12-fold range in mean concentrations among sites before accounting for the effects of size. Size-normalized Hg concentrations in the 200 mm SL size class were even more variable among sites. The highest mean concentration at a site (193.2 ng/g ww) was nearly 23-fold higher than the lowest site mean concentration (8.5 ng/g ww). Such extreme variation among sites in Mount Rainer NP suggests that local-scale factors play an important role in determining the ecological risk of Hg and emphasizes the need to sample from multiple locations in order to accurately characterize Hg risk to park resources as a whole.

North Cascades National Park

All three of the sites sampled in North Cascades NP had mean Hg concentrations below the average of all fish sampled in this study. After standardizing the fish to 200 mm SL, the mean Hg concentration in fish from North Cascades NP (73.3 ng/g ww) was similar to the mean of 200 mm fish across all parks. These data suggest that the ecological risk of Hg at the three sites sampled in North Cascades NP is low relative to many of the other parks. However, given the variation demonstrated among sites in this study, the limited sampling it is difficult to generalize across other sites in the park without more extensive sampling.

Olympic National Park

Mercury concentrations in fish across the five lakes sampled in Olympic NP (85.0 ng/g ww) were slightly higher than the mean concentration across the entire study. However, we found substantial variability in fish THg concentrations among lakes. In particular, size-adjusted THg concentrations in fish from Hoh Lake (253.0 ng/g ww) were more than 3.5-fold higher than those in Gladys Lake (71.5 ng/g ww), which had the lowest site-specific THg concentrations in the park. Our models of Hg risk to consumers reflects these higher concentrations and suggest that fish in Hoh Lake are likely to approach or exceed the EPA criterion for protection of human health and the avian benchmark for reproductive impairment above 180 mm. These results are similar to those reported by Landers and others (2008), who found Hg concentrations in fish from Hoh Lake were among the highest measured during their screening of national parks.

Rocky Mountain National Park

We sampled 19 sites in Rocky Mountain NP, allowing us to more rigorously examine within park variability in Hg concentrations among sites. Overall, the mean Hg concentration in fish from Rocky Mountain NP (ng/g ww) was slightly lower than the study-wide mean across all parks. Across sites within Rocky Mountain NP, concentrations varied by more than 6.5-fold between the sites with the lowest (Lake Haiyaha; 19.8 ng/g ww) and highest (Mirror Lake; 121.2 ng/g ww) concentrations. Our models of Hg risk suggest that most of the sites we sampled from Rocky Mountain NP had fish THg concentrations below the benchmarks of risk that we selected. However, brook trout from Mirror Lake and suckers from the Colorado and Fall Rivers are likely to exceed both the EPA human health criterion level and the avian reproductive impairment benchmark when the fish exceed 250 mm SL. In addition, we examined inter-annual variation at four sites in Rocky Mountain NP. At two of these sites (Nanita Lake and Mirror Lake), we found that there was no significant difference between the years sampled, whereas fish THg concentrations at Poudre Lake and Ypsilon Lake were significantly lower in 2012 compared to 2009. Additionally, two of the lakes sampled in this study (Mills Lake and Lone Pine Lake) also were sampled for another study in 2003 (Landers and others, 2008). Rainbow trout THg concentrations in Mills Lake were higher (87.5 ng/g) than in 2003 (less than 60 ng/g ww). Whereas THg concentrations in brook trout from Lone Pine Lake were lower (57.8 ng/g ww) than in 2003 (approximately 70 ng/g ww). Consistent with the results from Mount Rainer NP, our more intensive sampling at Rocky Mountain NP indicates substantial variation among sites, highlighting the importance of sampling multiple sites when characterizing the risk of Hg exposure within a national park.

Sequoia–Kings Canyon National Park

Four high-altitude lakes were sampled from Sequoia–Kings Canyon NPs. The mean fish THg concentration across all these sites (43.8 ng/g ww) was below the study-wide average across all fish analyzed in this study. Size-adjusted (200 mm SL) THg concentrations remained similarly low in all but Center Basin Lake, where the mean THg concentrations in golden trout increased to 207.3 ng/g ww. However, based on the size distribution of our sample of 30 individuals, 200 mm fish are likely rare in this population. Furthermore, two of the lakes from Sequoia–Kings Canyon NPs were sampled in 2008 (Center Basin Lake) or 2009 (Kern Point Lake) and again in 2012. Comparisons between sampling years indicate that Hg concentrations in fish from Kern Point Lake were remained similar between years, whereas Hg concentrations in Center Basin Lake fish were higher in 2012 than in 2008. Landers and others (2008) reported Hg concentrations higher than those observed in the current study from two additional high-altitude lakes in Sequoia–Kings Canyon NPs (Pear and Emerald Lakes), demonstrating that even among high-altitude lakes with potentially limited Hg inputs, fish THg concentrations can be quite variable.

Wrangell-St. Elias National Park

Lake-specific mean fish THg concentrations from the three lakes sampled at Wrangell-St. Elias NP spanned nearly 8-fold between rainbow trout from Summit Lake (53.3 ng/g ww) and Lake Trout from Tanada Lake (416.6 ng/g ww), which had the highest mean Hg concentration of any site from all of the parks examined in this study. After size-adjusting fish THg concentrations, we found that concentrations in 200 mm SL fish from Copper Lake (147.4 ng/g ww) were substantially higher than those from Summit Lake (65.4 ng/g ww). The mean size-adjusted THg concentration for 400 mm SL fish from Copper Lake (242.0 ng/g ww) and Tanada Lake (321.2 ng/g ww) approached or exceeded the

EPA fish tissue criterion, the avian reproductive impairment benchmark, and the tissue-based criterion for fish toxicity. Tanada Lake was one of the few lakes in the present study in which a relatively high proportion of fish were expected to exceed upper benchmarks for fish toxicity, reproductive impairment in low sensitivity birds, and at the largest sizes sampled, the no-consumption guideline proposed by the GLAG. The cause of such high concentrations in some fish from Wrangell-St. Elias NP is unclear and may reflect some combination of local biogeochemical processes that stimulate methylmercury production, the ecological structure of the lake's food web, or physiological characteristics of the fish themselves. For example, fish with high Hg concentrations may be exceptionally old and thus may have accumulated large quantities of Hg over their extended lives. Alternatively, fish in such northern lakes may grow slowly compared to fish in warmer, more productive systems resulting in little biodilution of ingested Hg through somatic growth.

Yellowstone National Park

Across all lakes, mean fish THg concentrations in Yellowstone NP (101.2 ng/g ww) were above the study-wide mean value from all parks. Size adjusted THg concentrations for 200 mm SL fish (119.8 ng/g ww) were among the highest measured in this study. Importantly, natural geothermal Hg sources occur throughout Yellowstone, though it is unclear if those sources play a role in fish bioaccumulation.

Yosemite National Park

The two sites sampled at Yosemite NP display starkly contrasting patterns of Hg concentrations. At one site, Spillway Lake, fish THg concentrations were uniformly low; the site mean (38.7 ng/g ww) was one-half of the study-wide mean across all parks. In contrast, THg concentrations in fish from Mildred Lake (174.4 ng/g ww) were more than twice the study-wide mean. Moreover, individual fish concentrations had a 15-fold range within the lake. Importantly, the highest individual fish THg concentration in the entire study (1,109 ng/g ww) was measured in a brook trout from Mildred Lake. This was the only fish that exceeded the no-consumption guideline proposed by the GLAG, and was 1.6-times greater than the next highest concentration measured in this study. The source of such variation within a lake is unclear, but future efforts should aim to identify the factors regulating accumulation in individuals and determining whether this variability is representative of other lakes in the park.

Zion National Park

As in Capitol Reef NP, all fish sampled from Zion NP were speckled dace and displayed high Hg concentrations (241.5 ng/g ww) for a small, low trophic level fish. At both sites along the Virgin River, mean Hg concentrations were more than 3-fold higher than the study-wide mean concentration. Furthermore, variation within and between these isolated sites was very low. As in Capitol Reef, the potential for dace to serve as prey for higher trophic position consumers, and indicators of Hg exposure in other invertebrate-feeding taxa, suggest that more research should examine factors regulating Hg accumulation in the lower trophic levels of these systems.

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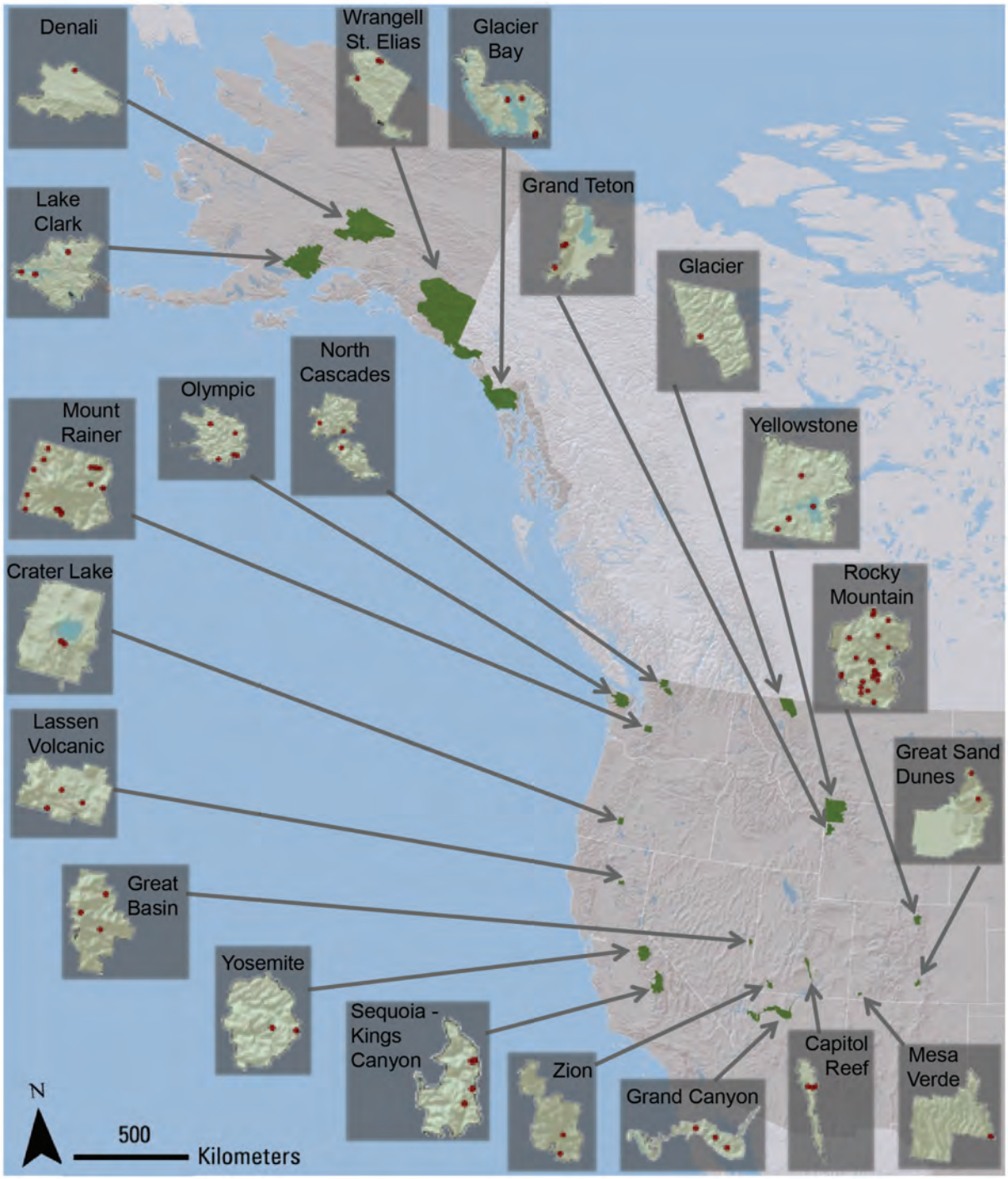


Figure 1. Spatial distribution of the 21 national parks in the Western United States sampled in this study between 2008 and 2012. Shaded polygons on base map indicate park boundaries. Red circles within each inset park boundary indicate specific sampling locations for each park.

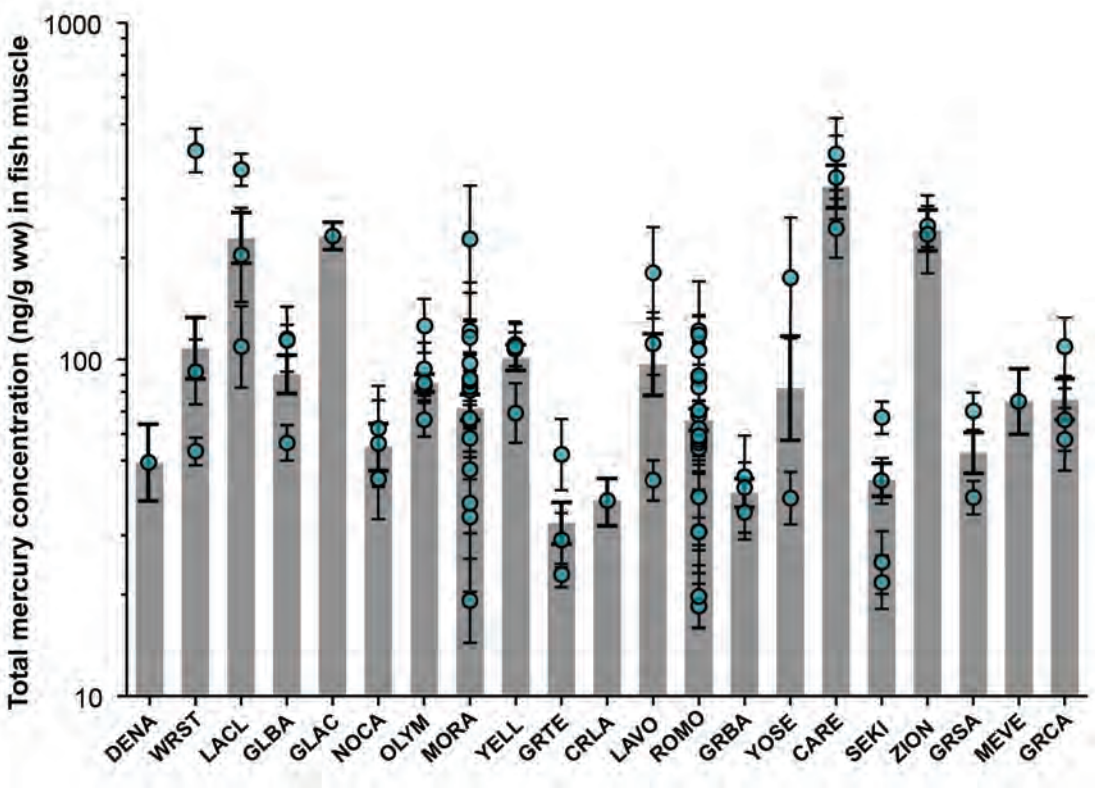


Figure 2. Total mercury (THg) concentrations (ng/g ww) in fish muscle from 21 national parks in the Western United States. Bar height and bolded error bars represent the park-wide geometric mean THg concentration and 95-percent confidence interval, respectively. Colored circles and thin error bars represent site-specific geometric mean THg concentration and 95-percent confidence interval, respectively. Parks are ordered by decreasing latitude, and park abbreviations can be referenced to park names in table 1.

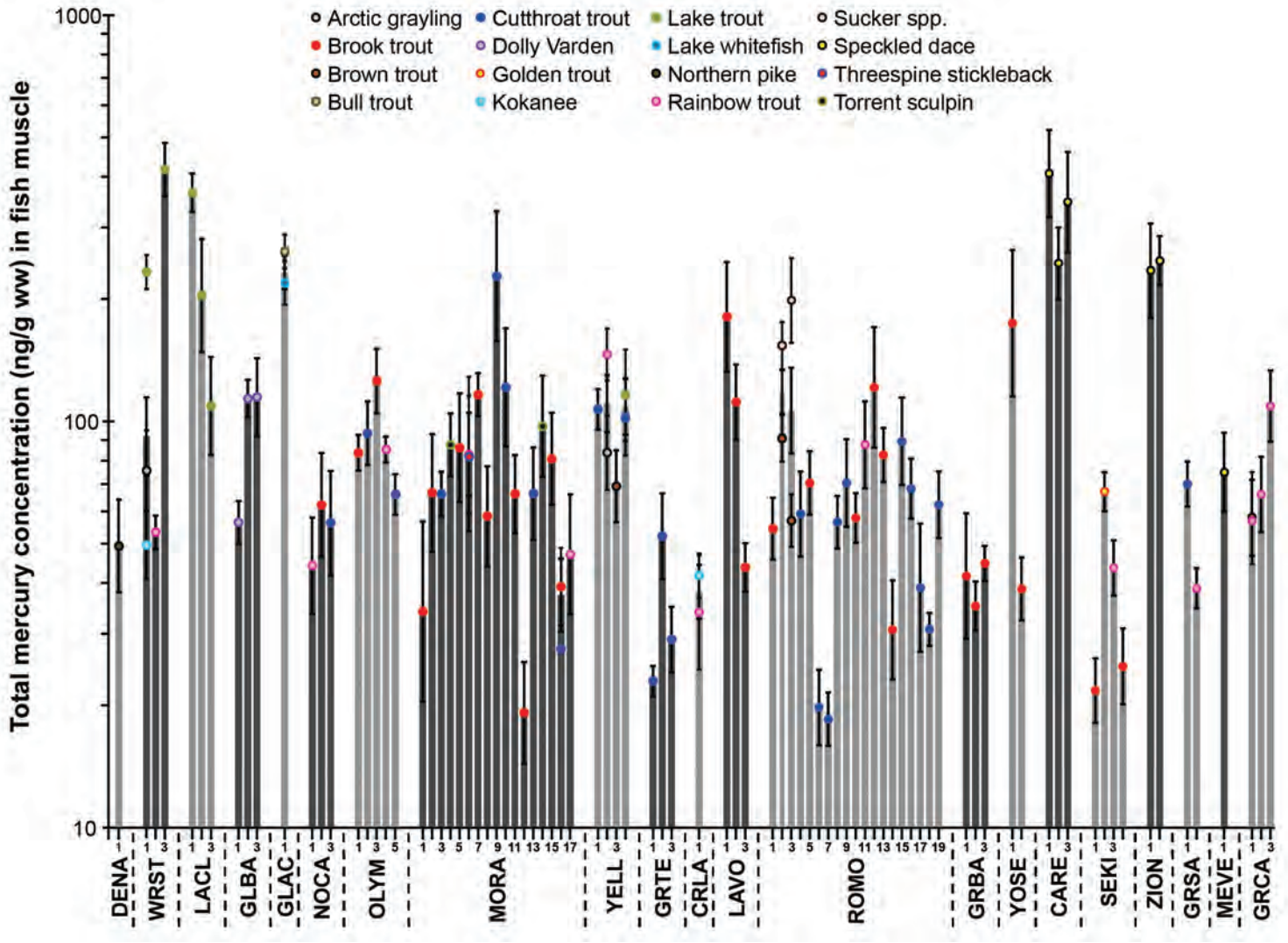


Figure 3. Total mercury (THg) concentrations (ng/g ww) in fish muscle from individual sites within 21 national parks in the Western United States. Bar height and bolded error bars represent site-specific geometric means and 95-percent confidence intervals. Circles represent species-specific geometric means in 95-percent confidence intervals within each site. Parks are ordered by decreasing latitude, and park abbreviations and site numbers can be referenced to park name in table 1.

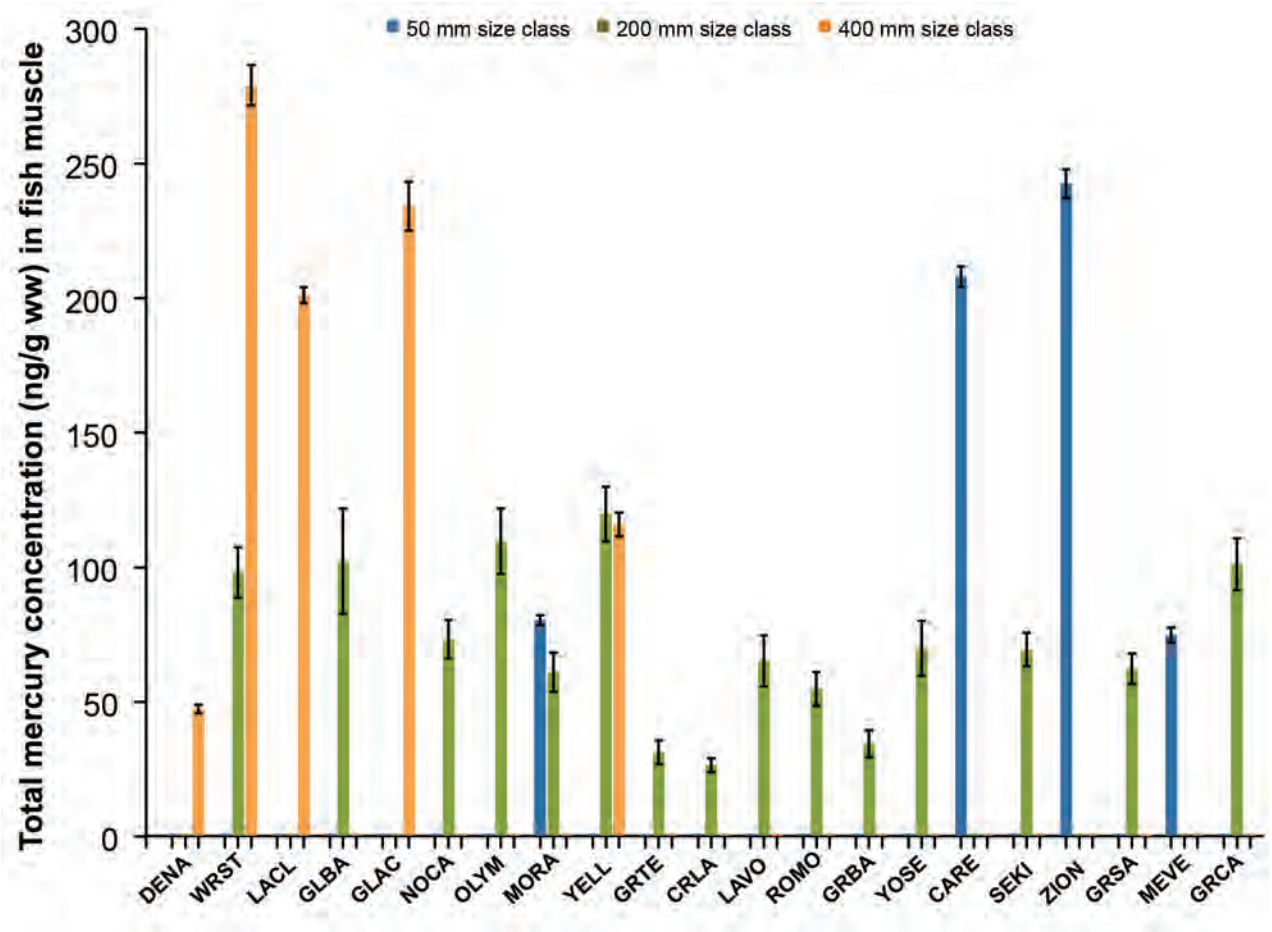


Figure 4. Size-normalized least-square (LS) total mercury (THg) concentrations in fish from 21 national parks in the Western United States. LS mean concentrations control for the influence of fish species and site within each park. Blue bars are LS means for fish species normalized to 50 mm size, green bars are LS means for fish species normalized to 200 mm size, orange bars are LS means for fish species normalized to 400 mm size. Parks are ordered by decreasing latitude, and park abbreviations can be referenced to park name in table 1. Species comprising each size category is discussed in section, “Methods.”

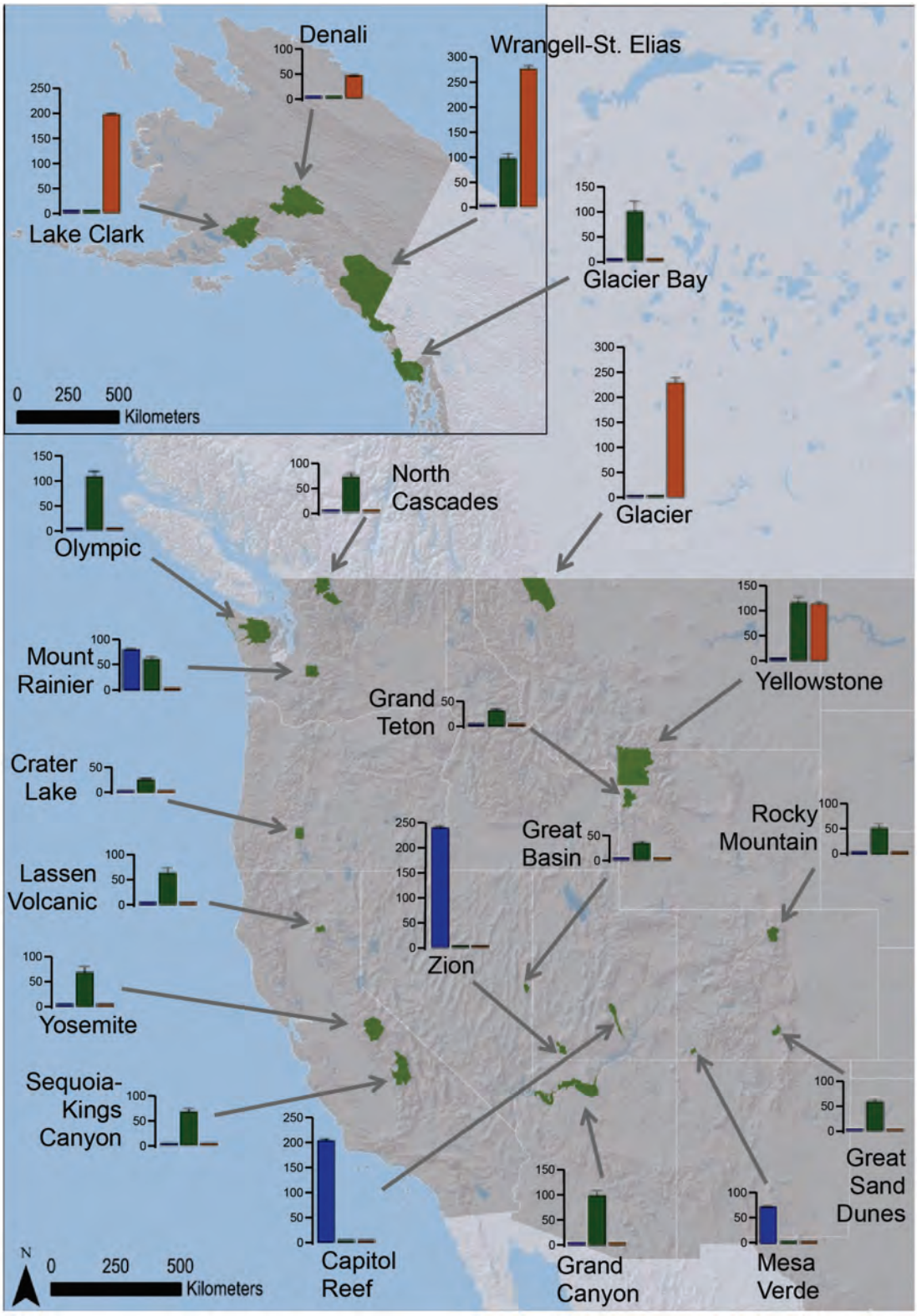


Figure 5. Least-square mean fish muscle total Hg concentrations (ng/g ww) in three size-normalized classes (blue/left = 50 mm, green/middle = 200 mm, orange/right = 400 mm) from 21 national parks in the Western United States.

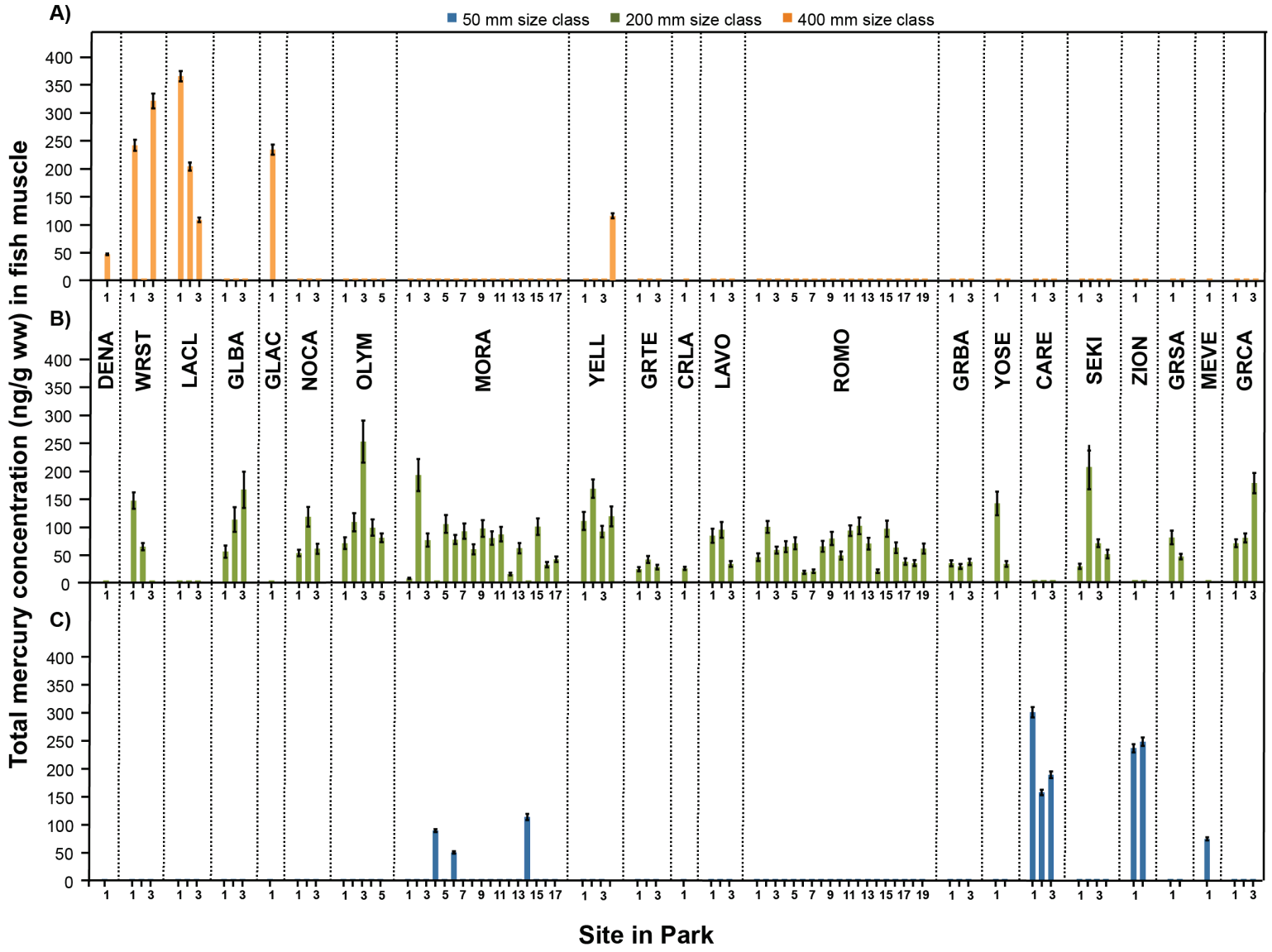


Figure 6. Least-square mean (whiskers = standard error) total mercury (THg) concentrations in fish muscle from individual sites in 21 national parks in the Western United States. Concentrations are size normalized for (A) 400 mm SL, (B) 200 mm SL, (C) 50 mm SL fish. Park abbreviations and site numbers can be referenced to park name in table 1.

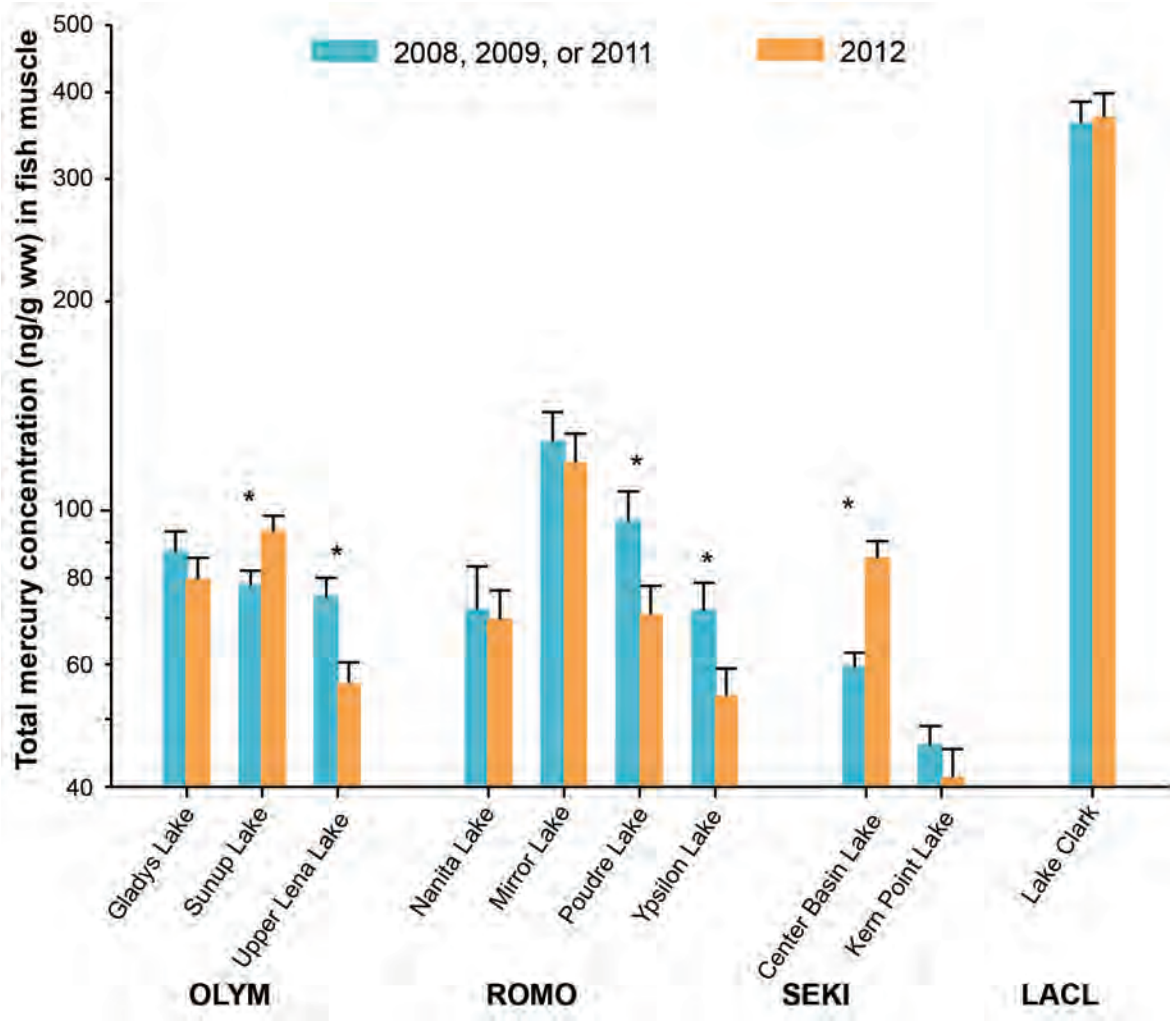


Figure 7. Inter-annual comparisons of fish total mercury concentrations (ng/g ww) in muscle tissue from 10 sites in four national parks in the Western United States. Error bars represent standard error. Asterisks indicate significant differences ($p<0.05$) between years within a site. OLYM, Olympic NP, ROMO, Rocky Mountain NP; SEKI, Sequoia-Kings Canyon NP; and LACL, Lake ClarkNP.

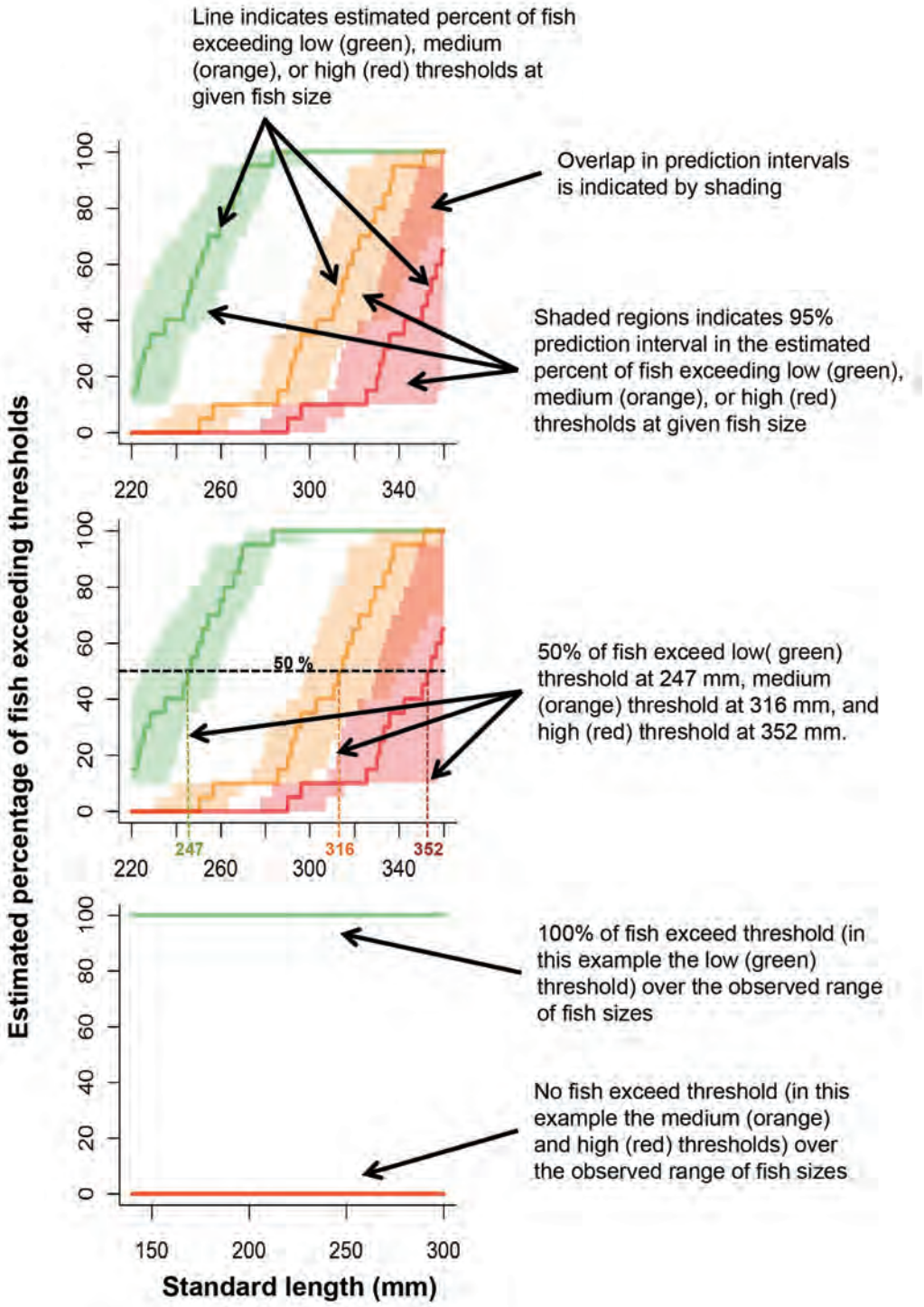


Figure 8. Example size-risk profile to evaluate proportion of fish exceeding defined toxicological benchmarks. Each color represents a defined risk benchmark. Solid lines indicated the estimated proportion of fish exceeding benchmarks across the size spectrum. Shaded regions represent the 95-percent prediction interval around the benchmark. A solid line at 0 or 100 percent indicates that all no fish or all fish, respectively, exceed the specified benchmark across the size spectra.

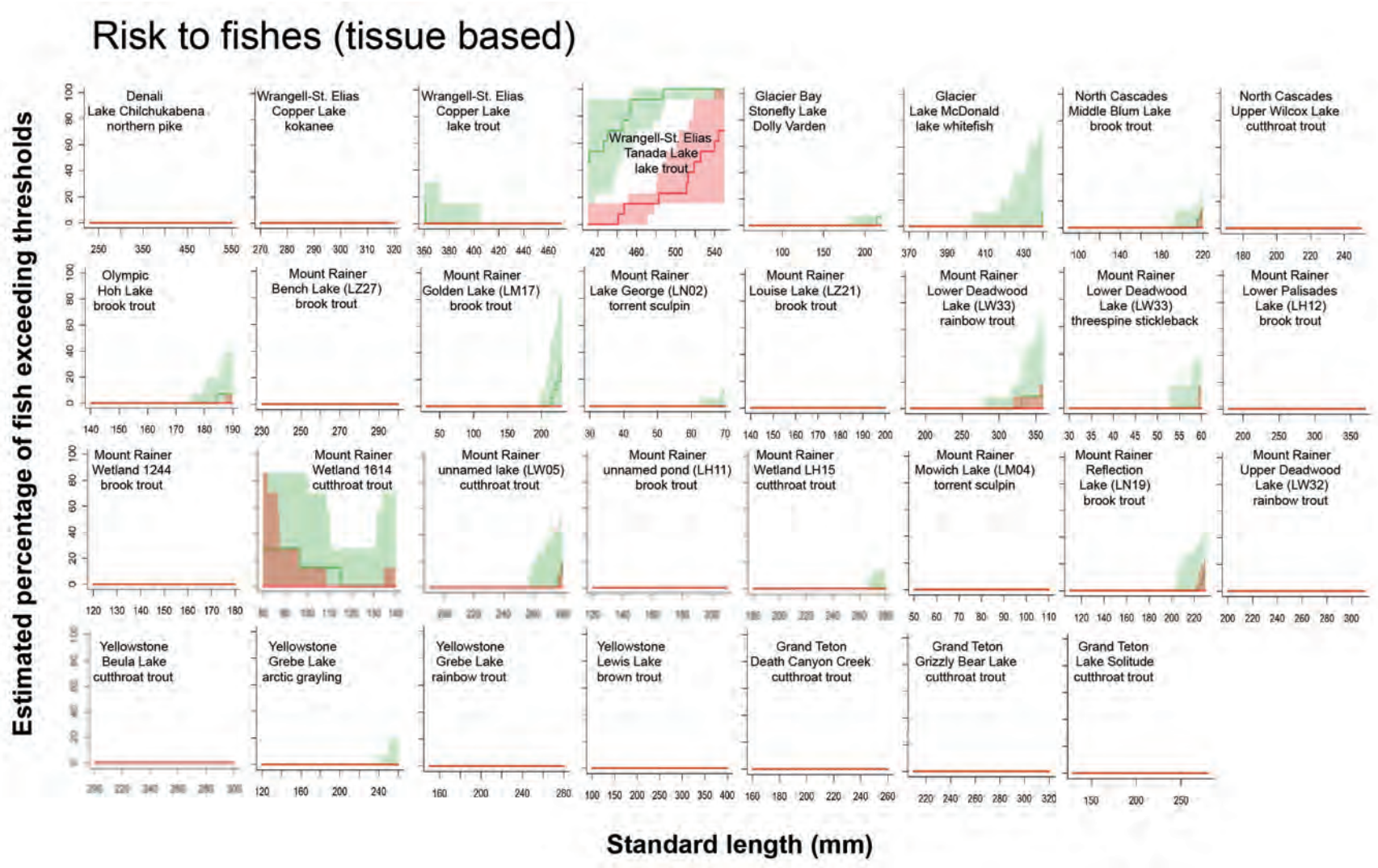


Figure 9. Modeled percentage of fish across the size range sampled in each population with whole-body total mercury concentrations that exceed benchmarks at a given size for a generic no-observed-effects residue (green; 200 ng/g ww), and lowest-observed-effects-residue (red; 300 ww) for fish health at 21 national parks in the Western United States. Parks are ordered by decreasing latitude. Figure continues on next page.

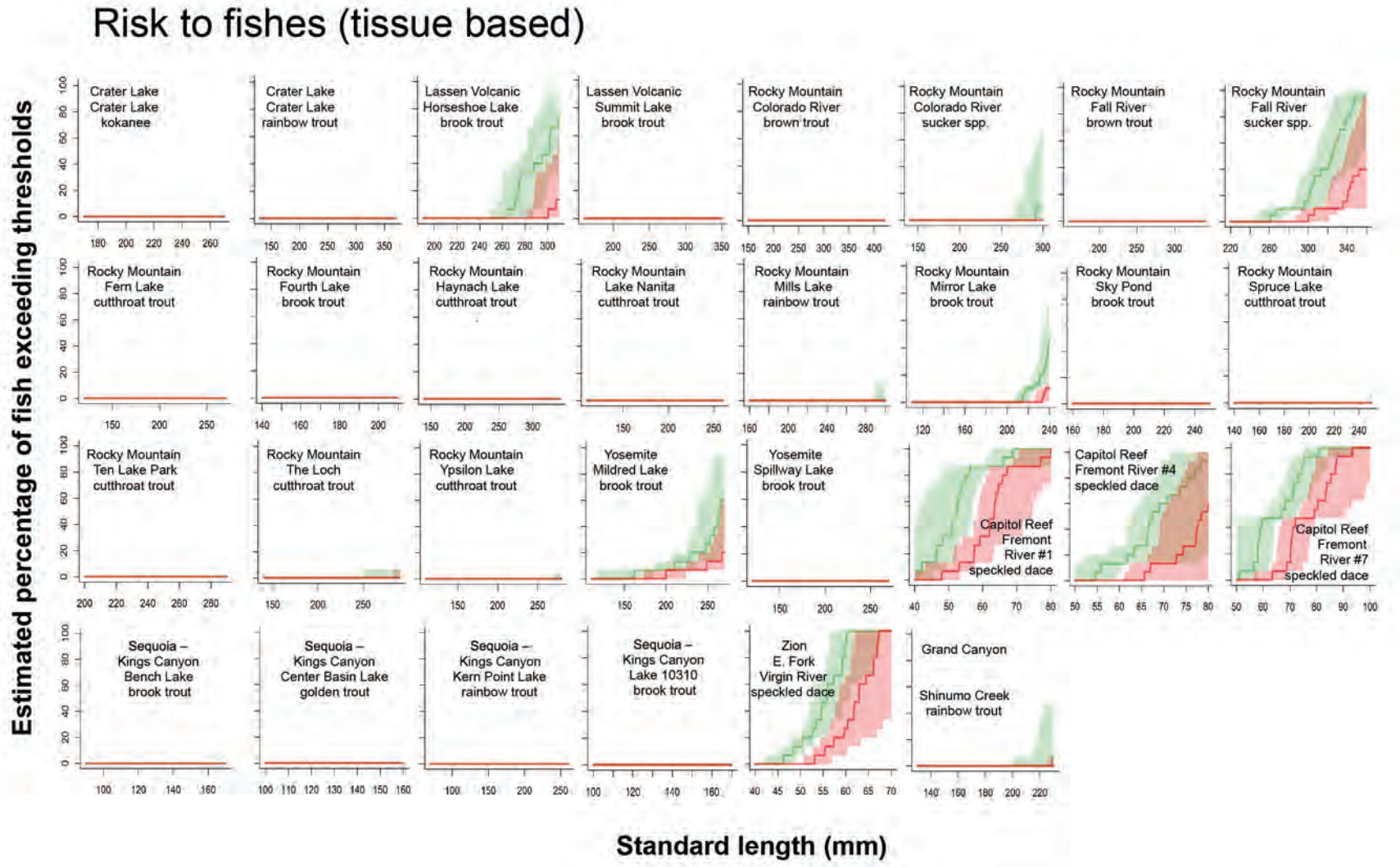


Figure 9.—Continued. Modeled percentage of fish across the size range sampled in each population with whole-body total mercury concentrations whole-body total mercury concentrations that exceed benchmarks for a generic no-observed-effects residue (green; 200 ng/g ww), and lowest-observed-effects-residue (red; 300 ng/g ww) for fish health in 21 national parks in the Western United States. Parks are ordered by decreasing latitude.

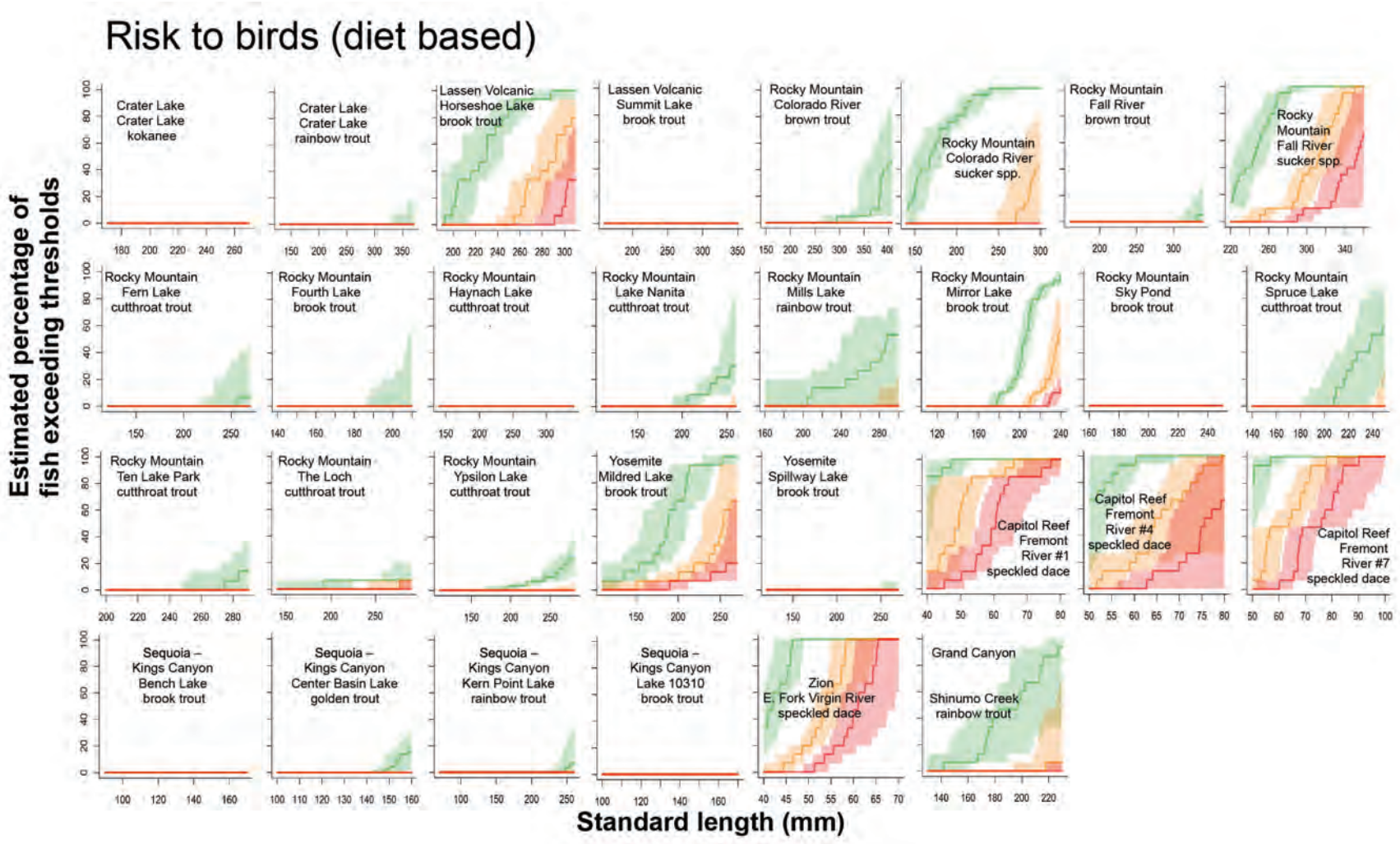


Figure 10. Modeled percentage of fish across the size range sampled in each population with whole-body total mercury concentrations that exceed dietary toxicity benchmarks for piscivorous birds that can be classified as high (green; 90 ng/g ww), medium (orange; 180 ng/g ww; common loon reproductive impairment), or low (red; 270 ng/g ww) sensitivity in 21 national parks in the Western United States. Parks are ordered by decreasing latitude. Figure continues on next page.

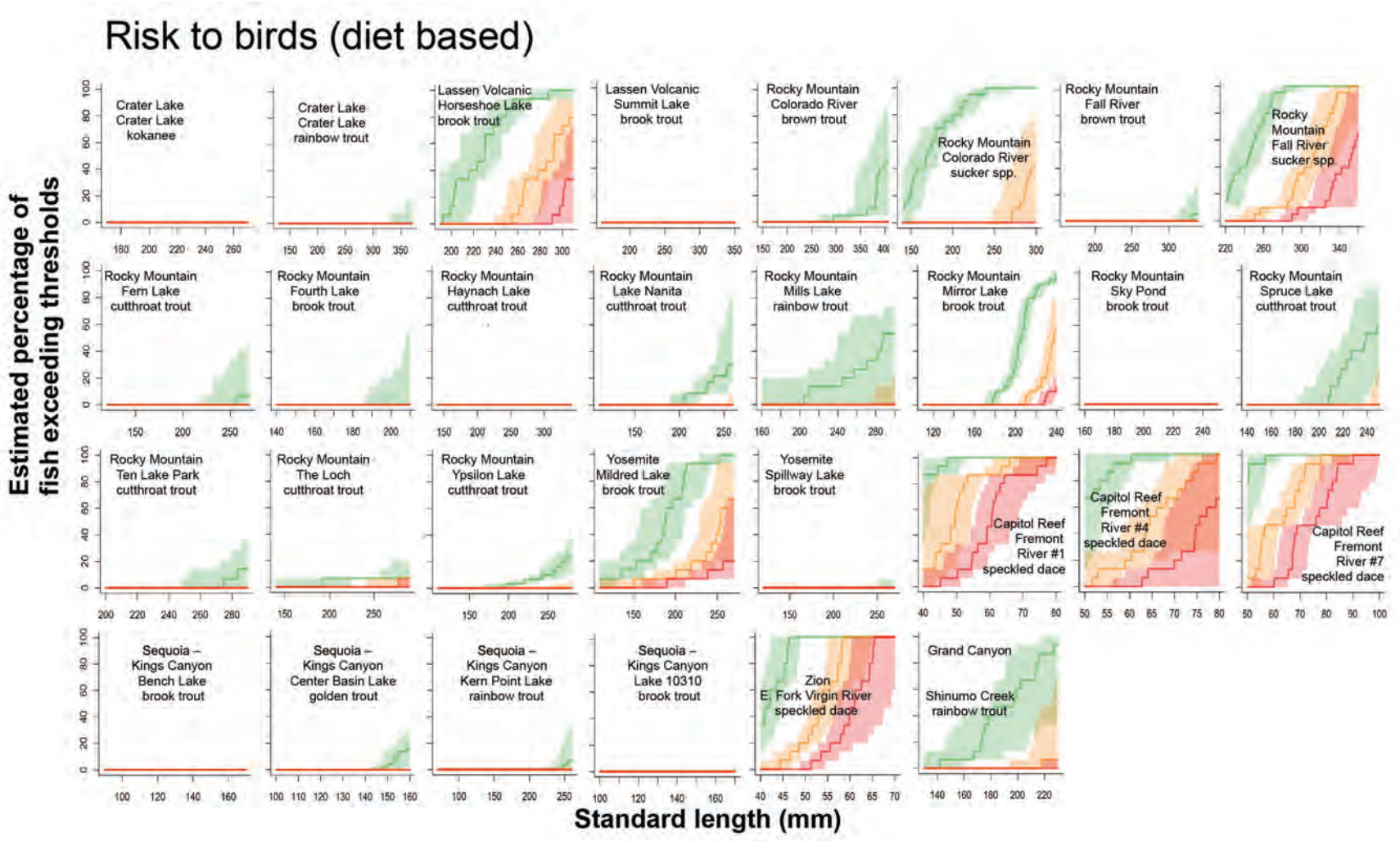


Figure 10.—Continued. Modeled percentage of fish across the sampled size range in each population with whole-body total mercury concentrations that exceed dietary toxicity benchmarks for piscivorous birds that can be classified as high (green; 90 ng/g ww), medium (orange; 180 ng/g ww; common loon reproductive impairment), or low (red; 270 ng/g ww) sensitivity in 21 national parks in the Western United States. Parks are ordered by decreasing latitude.

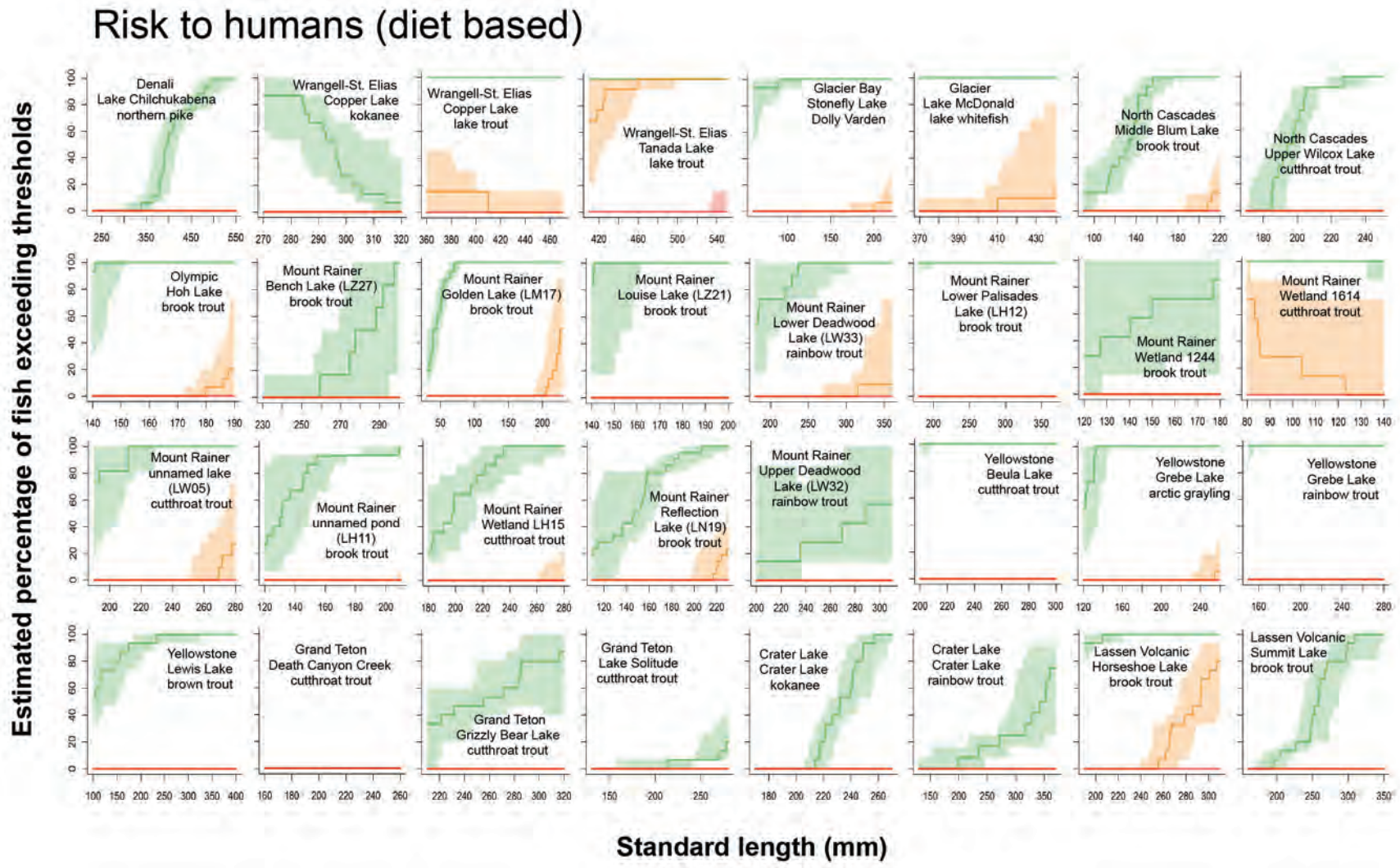


Figure 11. Modeled percentages of fish across the sampled size range in each population with muscle total mercury concentrations exceeding the Great Lakes Advisory Group's (GLAG) unlimited consumption threshold (green; 50 ng/g ww), the Environmental Protection Agency's fish consumption criterion (orange; 300 ng/g ww), and the GLAG's no-consumption threshold (red; 950 ng/g ww) in 21 national parks in the Western United States. Parks are ordered by decreasing latitude.

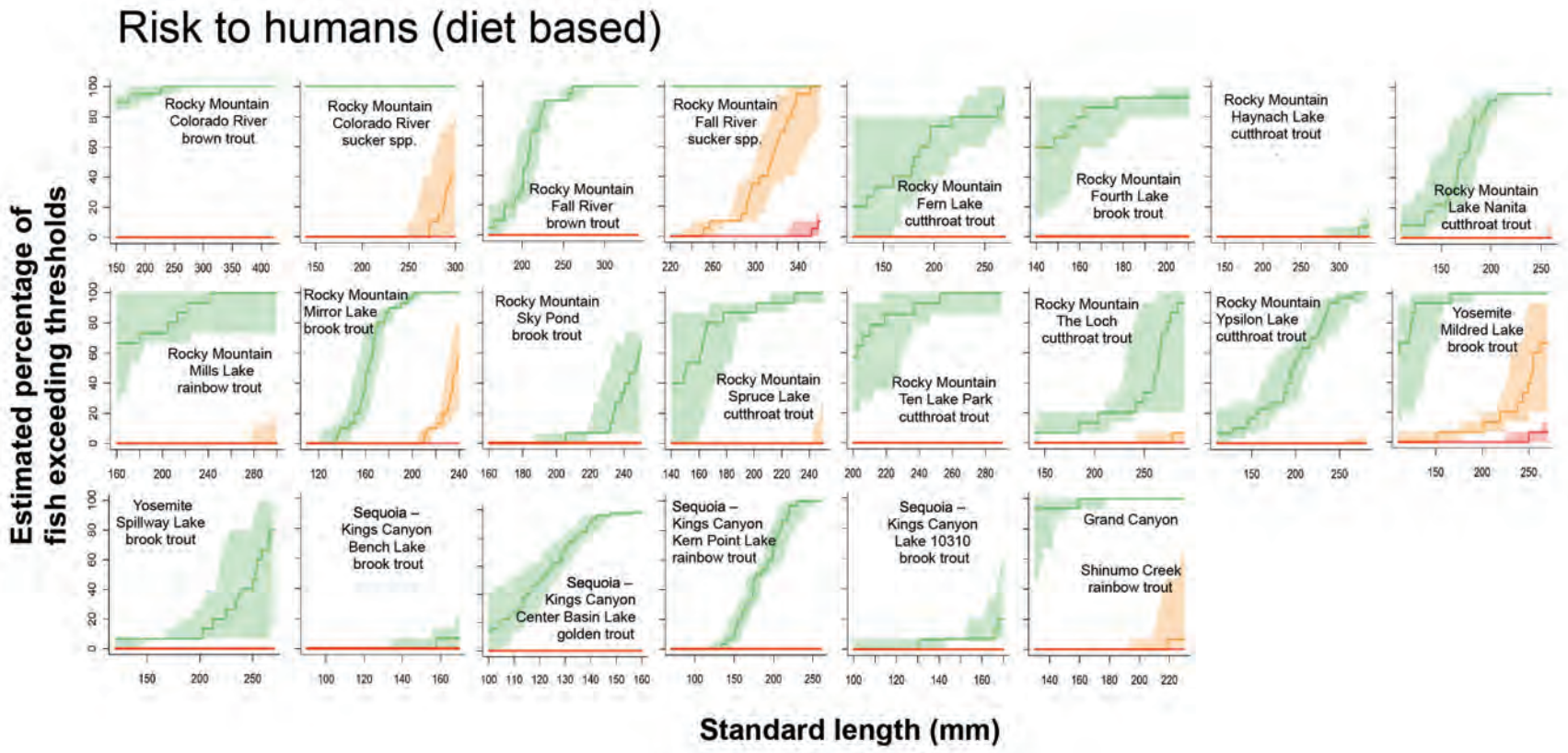


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Table 1. Site locations and sampling information for 21 national parks in the Western United States sampled between 2008 and 2012.

Park / Site	Site ID	Latitude	Longitude	Altitude (m)	Habitat	Species	Year Sampled	n	Standard Length (mm)		SR[a]
									Mean	Range	
Capitol Reef											
Fremont River #1	1	38.2827	-111.1157	1502	river	speckled dace	2012	15	58	46-74	Y
Fremont River #4	2	38.2815	-111.1794	1577	river	speckled dace	2012	15	61	55-71	Y
Fremont River #7	3	38.2856	-111.2416	1649	river	speckled dace	2012	15	67	53-99	Y
Crater Lake											
Crater Lake	1	42.9057	-122.1017	1884	lake	kokanee	2011	15	207	172-265	Y
						rainbow trout	2011	12	254	137-370	Y
Denali											
Lake Chilchukabena	1	63.9153	-151.5083	191	lake	northern pike	2012	17	407	232-546	Y
Glacier											
Lake McDonald	1	48.5691	-113.9362	963	lake	bull trout	2008	5	434	386-494	N
Glacier Bay											
Falls Creek	1	58.4443	-135.5988	226	creek	Dolly Varden	2012	15	96	73-127	N
North Skidmore Lake	2	58.8451	-136.6839	98	lake	Dolly Varden	2012	15	161	128-203	N
Stonefly Lake	3	58.9674	-136.3379	38	lake	Dolly Varden	2012	15	141	61-219	Y
						lake whitefish	2008	10	396	371-431	Y
Grand Canyon											
Bright Angel Creek	1	36.1228	-112.0800	887	lake	brown trout	2012	2	139	104-174	N
						rainbow trout	2012	10	131	96-263	N
Havasu Creek	2	36.2980	-112.7402	621	creek	rainbow trout	2012	15	200	140-268	N
Shinumo Creek	3	36.2515	-112.33186	794	creek	rainbow trout	2012	15	171	131-222	Y
Grand Teton											
Death Canyon	1	43.6702	-110.87452	2564	creek	cutthroat trout	2012	15	214	162-253	Y
Grizzly Bear Lake	2	43.8027	-110.8107	2814	lake	cutthroat trout	2012	15	254	219-315	Y
Lake Solitude	3	43.7926	-110.8448	2758	lake	cutthroat trout	2012	15	227	137-278	Y
Great Basin											
Baker Lake	1	38.9577	-114.3100	3243	lake	brook trout	2011	9	230	200-252	N
Lehman Creek	2	38.9246	-114.2381	2404	creek	brook trout	2011	15	150	127-167	N
Snake Creek	3	39.01468	-114.2428	2281	creek	brook trout	2011	15	154	122-204	N
Great Sand Dunes											
Medano Lake	1	37.8564	-105.4847	3513	lake	cutthroat trout	2009	15	165	110-212	N
Sand Creek	2	37.9350	-105.5230	3365	creek	rainbow trout	2009	14	190	153-258	N

Park Site	Site ID	Latitude	Longitude	Altitude (m)	Habitat	Species	Year Sampled	n	Standard Length (mm)		SR[a]
									Mean	Range	
Lake Clark											
Lake Clark[b]	1	60.0187	-154.7574	77	lake	lake trout	2011	16	476	364-648	N
						lake trout	2012	12	478	428-580	N
Lake Kontrashibuna	2	60.1795	-154.2223	140	lake	lake trout	2011	14	358	315-398	N
						lake trout	2012	2	383	378-387	N
Telaquana Lake	3	60.9520	-153.7625	372	lake	lake trout	2011	15	483	412-586	N
Lassen Volcanic											
Horseshoe Lake	1	40.4724	-121.3358	1996	lake	brook trout	2009	15	249	197-305	Y
Ridge Lake	2	40.4138	-121.4630	1984	lake	brook trout	2009	17	187	143-210	N
Summit Lake	3	40.4929	-121.4233	2038	lake	brook trout	2009	15	221	165-346	Y
Mesa Verde											
Mancos River	1	37.2204	-108.3410	1886	river	speckled dace	2012	10	56	43-69	N
Mount Rainier											
Bench Lake (LZ27)	1	46.7622	-121.6986	1386	lake	brook trout	2012	6	262	237-298	Y
Golden Lake (LM17)	2	46.8887	-121.9002	1372	lake	brook trout	2012	16	73	36-229	Y
Green Lake (LC07)	3	46.9769	-121.8590	974	lake	cutthroat trout	2012	6	257	214-285	N
Lake George (LN02)	4	46.7917	-121.9040	1308	lake	torrent sculpin	2012	16	49	37-62	Y
Louise Lake (LZ21)	5	46.7704	-121.7157	1405	lake	brook trout	2012	6	171	145-192	Y
Lower Deadwood Lake (LW33)	6	46.8871	-121.5227	1602	lake	rainbow trout	2012	11	239	185-353	Y
						stickleback[c]	2012	6	42	34-59	Y
Lower Palisades Lake (LH12)	7	46.9533	-121.5903	1682	lake	brook trout	2012	19	277	180-365	Y
Wetland 1244	8	46.7704	-121.7259	1487	lake	brook trout	2012	7	158	122-179	Y
Wetland 1614	9	46.7401	-121.8836	669	lake	cutthroat trout	2012	7	108	89-135	Y
Unnamed Lake (LW05)	10	46.9561	-121.5719	1649	lake	cutthroat trout	2012	11	238	195-278	Y
Unnamed Pond (LH11)	11	46.9554	-121.5932	1666	lake	brook trout	2012	15	159	122-201	Y
Wetland 583	12	46.8918	-121.5948	1125	lake	brook trout	2012	9	164	131-188	N
Unnamed wetland (LH15)	13	46.9517	-121.6178	1679	lake	cutthroat trout	2008	14	218	187-276	Y
Mowich Lake (LM04)	14	46.9339	-121.864	1506	lake	torrent sculpin	2008	7	99	92-105	Y
						torrent sculpin	2012	2	56	53-59	Y
Reflection Lake (LN19)	15	46.7693	-121.7294	1483	lake	brook trout	2012	21	175	114-227	Y
Snow Lake	16	46.7570	-121.6992	1432	lake	brook trout	2012	13	210	179-239	N
						cutthroat trout	2012	2	217	193-241	N
Upper Deadwood Lake (LW32)	17	46.8890	-121.5248	1599	lake	rainbow trout	2008	7	261	203-305	Y
North Cascades											
George Lake	1	48.7061	-121.1722	268	lake	rainbow trout	2011	10	189	171-226	N
Middle Blum Lake	2	48.7500	-121.4956	1529	lake	brook trout	2008	15	142	91-220	Y
Upper Wilcox Lake	3	48.6011	-121.1717	1569	lake	cutthroat trout	2008	12	204	170-248	Y

Park Site	Site ID	Latitude	Longitude	Elevation (m)	Habitat	Species	Year Sampled	n	SL (mm)[a]		SR[b]
									Mean	Range	
Olympic											
Gladys Lake[b]	1	47.8767	-123.3578	1646	lake	brook trout	2011	15	166	159-180	N
						brook trout	2012	15	167	150-182	N
Hagen Lake	2	47.6192	-123.2680	1446	lake	cutthroat trout	2012	15	212	175-238	N
Hoh Lake	3	47.8988	-123.7863	1387	lake	brook trout	2012	15	165	142-185	Y
Sun Up Lake[b]	4	47.5314	-123.4862	1227	lake	cutthroat trout	2011	15	242	232-257	N
						cutthroat trout	2012	15	250	219-269	N
Upper Lena Lake[b]	5	47.6331	-123.2080	1389	lake	rainbow trout	2011	15	171	149-187	N
Rocky Mountain											
Black Lake	1	40.2653	-105.6410	3242	lake	brook trout	2012	15	188	126-226	N
Colorado River	2	40.2773	-105.8504	2647	river	brown trout	2012	20	272	152-413	Y
						sucker spp	2012	20	193	145-292	Y
Fall River	3	40.4014	-105.6063	2590	river	brown trout	2012	20	229	166-338	Y
						sucker spp	2012	20	273	220-359	Y
Fern Lake	4	40.3368	-105.6763	2913	lake	cutthroat trout	2012	15	209	126-270	Y
Fourth Lake	5	40.2217	-105.6861	3167	lake	brook trout	2012	15	178	146-206	Y
Haynach Lake	6	40.3467	-105.7646	3378	lake	cutthroat trout	2012	15	237	141-340	Y
Lake Haiyaha	7	40.3047	-105.6622	3120	lake	cutthroat trout	2012	15	255	182-309	N
Lake Louise	8	40.5083	-105.6206	3369	lake	cutthroat trout	2012	14	271	222-314	N
Lake Nanita[b]	9	40.2560	-105.7165	3291	lake	cutthroat trout	2008	8	231	187-258	Y
						cutthroat trout	2012	15	188	111-260	Y
Lone Pine Lake	10	40.2327	-105.7232	3134	lake	brook trout	2012	14	141	91-178	N
Mills Lake	11	40.2895	-105.6417	3033	lake	rainbow trout	2012	15	226	167-295	Y
Mirror Lake[b]	12	40.5380	-105.6984	3364	lake	brook trout	2009	15	211	153-237	Y
						brook trout	2012	15	190	115-238	Y
Poudre Lake[b]	13	40.4222	-105.8089	3282	lake	brook trout	2009	15	202	129-242	N
						brook trout	2012	15	203	108-264	N
Sky Pond	14	40.2782	-105.6688	3315	lake	brook trout	2012	15	215	162-246	Y
Spruce Lake	15	40.3423	-105.6871	2950	lake	cutthroat trout	2012	15	206	148-242	Y
Ten Lake Park	16	40.2104	-105.7194	3415	lake	cutthroat trout	2012	14	239	206-288	Y
The Loch	17	40.2925	-105.6570	3109	lake	cutthroat trout	2012	15	218	148-285	Y
Upper Hutcheson Lake	18	40.1736	-105.6470	3417	lake	cutthroat trout	2012	15	208	183-250	N
Ypsilon Lake[b]	19	40.4436	-105.6633	3218	lake	cutthroat trout	2009	15	215	156-275	Y
Sequoia-Kings Canyon											
Bench Lake	1	36.9488	-118.4651	3224	lake	brook trout	2009	15	131	92-165	Y
Center Basin Lake[b]	2	36.7305	-118.3960	3517	lake	golden trout	2008	30	136	103-156	Y
						golden trout	2012	15	138	100-157	Y
Kern Point Lake[b]	3	36.6013	-118.4319	3281	lake	rainbow trout	2009	15	166	108-224	Y
Lake 10310	4	36.9591	-118.4354	3297	lake	brook trout	2012	15	143	101-168	Y

Park Site	Site ID	Latitude	Longitude	Elevation (m)	Habitat	Species	Year Sampled	n	SL (mm)[a]		SR[b]
									Mean	Range	
Wrangell-St. Elias											
Copper Lake	1	62.4256	-143.5550	886	lake	arctic grayling	2008	15	326	274-374	N
						kokanee	2008	15	295	278-311	Y
						lake trout	2008	13	417	365-470	Y
Summit Lake	2	61.3156	-144.1919		lake	rainbow trout	2009	15	250	123-405	N
Tanada Lake	3	62.4258	-143.3717	880	lake	lake trout	2009	13	466	418-542	Y
						rainbow trout	2012	12	180	151-198	N
Yellowstone											
Beula Lake	1	44.1598	-110.7670	2261	lake	cutthroat trout	2012	15	239	204-300	Y
Grebe Lake	2	44.7516	-110.5578	2450	lake	arctic grayling	2012	15	166	128-255	Y
						rainbow trout	2012	15	234	152-273	Y
Lewis Lake	3	44.3068	-110.6305	2375	lake	brown trout	2012	15	187	109-394	Y
Yellowstone Lake	4	44.4659	-110.3330	2361	lake	cutthroat trout	2012	15	266	243-294	N
						lake trout	2012	15	273	240-325	N
						cutthroat trout	2012	15	221	115-262	Y
Yosemite											
Mildred Lake	1	37.8202	-119.4407	2916	lake	brook trout	2009	15	204	117-269	Y
Spillway Lake	2	37.8408	-119.2321	3189	lake	brook trout	2009	15	192	124-263	Y
						rainbow trout	2012	15	170	73-252	Y
Zion											
E. Fork Virgin River	1	37.1594	-112.9686	1192	river	speckled dace	2012	15	50	40-61	Y
N. Fork Virgin River	2	37.2413	-112.9588	1294	river	speckled dace	2012	15	39	34-44	N

[a] Size regression used: Y-yes, N-no.
[b] Lakes used in inter-annual comparison. Lake Kontrashibuna was excluded from intra-annual comparisons because only two fish were collected in 2012.
[c] Threespine stickleback.

Table 2. Total mercury concentrations (THg; ng/g ww) in muscle of fish from 21 national parks in the Western United States.

[Values are reported as geometric means, 95percent confidence intervals (CI), and range, and least-square mean (LSM) concentrations controlling for the effects of size, species, and site at 50, 200, and 400 mm standardized lengths]

Park	Park Abbreviation	Total n	Geometric Mean	95percent CI	Range	50 mm			200 mm			400 mm		
						n	LSM	SE	n	LSM	SE	n	LSM	SE
Capitol Reef	CARE	45	325.6	281.4 - 376.9	136.7 - 805.4	45	207.9	3.7		-			-	
Crater Lake	CRLA	27	38.0	32 - 44.3	16.8 – 76.0		-		27	26.6	2.6		-	
Denali	DENA	17	49.3	37.9 - 64.1	23.7 - 88.8		-			-		17	47.4	1.6
Glacier	GLAC	15	232.4	211.6 - 255.3	167.3 - 297.9		-			-		15	234.1	9.1
Glacier Bay	GLBA	45	90.2	79.1 - 102.9	41.0 - 203.1		-		45	102.3	19.6		-	
Grand Canyon	GRCA	42	76.0	66.1 - 87.5	31.8 - 241.2		-		42	101.2	9.6		-	
Grand Teton	GRTE	45	32.6	28.3 - 37.6	16.2 – 99.0		-		45	31.3	4.5		-	
Great Basin	GRBA	39	40.0	36.3 - 44.2	19.0 - 85.5		-		39	34.5	5.0		-	
Great Sand Dunes	GRSA	29	52.7	45.8 - 60.6	29.1 - 136.6		-		29	62.4	5.6		-	
Lake Clark	LACL	59	229.3	192.8 - 272.8	35.8 – 691.0		-			-		59	201.0	2.9
Lassen Volcanic	LAVO	47	96.4	78.1 - 119	28.6 - 493.4		-		47	65.3	9.5		-	
Mesa Verde	MEVE	10	74.9	59.9 - 93.7	45.7 - 115.4	10	74.9	2.9		-			-	
Mount Rainier	MORA	207	71.5	65.8 - 78.5	12.5 - 384.5	35	80.4	1.9	172	61.0	7.3		-	
North Cascades	NOCA	37	54.9	46.7 - 64.4	22.4 - 209.3		-		37	73.3	7.2		-	
Olympic	OLYM	117	85.0	80 - 90.3	34.9 - 208.8		-		337	109.7	12.1		-	
Rocky Mountain	ROMO	385	66.1	61.4 - 71.1	9.9 - 528.3		-		385	54.8	6.3		-	
Sequoia - Kings Canyon	SEKI	105	43.8	39.1 - 49	13.3 - 124.5		-		105	69.5	6.3		-	
Wrangell-St. Elias	WRST	71	107.9	87.4 - 133.1	27.8 - 632.3		-		45	98.15	9.41	26	278.8	7.4
Yellowstone	YELL	90	101.2	92.7 - 110.5	44.6 - 312.2		-		75	119.8	10.2	15	116.0	4.3
Yosemite	YOSE	30	82.1	57.5 - 117.2	24.9 - 1108.6		-		30	70.0	10.2		-	
Zion	ZION	30	241.5	209.7 - 278.2	95.9 - 532.6	30	242.5	5.4		-			-	

Table 3. Total mercury concentrations (THg; ng/g ww) and coefficients of variation (CV) in fish muscle from 86 sites in 21 national parks in the Western United States.

[Values are reported as geometric means and 95 percent confidence intervals (95% CI), and least-square mean (LSM) concentrations controlling for the effects of size, species, and site at 50 mm, 200 mm, and 400 mm standardized lengths]

Park Site	Geometric Mean	95% CI	50 mm[b]		200 mm[b]		400 mm[b]		CV
			LSM	SE	LSM	SE	LSM	SE	
All Parks	**77.7**	**73.6 - 80.8**							**0.67**
Capitol Reef	**325.6**	**281.4 - 376.9**	**207.9**	**3.7**					**0.88**
Fremont River #1	407.3	318.3 - 521.1	301.0	9.4					0.31
Fremont River #4	244.7	199.8 - 299.7	157.8	4.9					0.31
Fremont River #7	346.5	260.4 - 461.1	189.4	5.9					0.30
Crater Lake	**38.0**	**32 - 44.3**			**26.6**	**2.6**			**NA**
Crater Lake	38.0	32.7 - 44.3			26.6	2.6			0.28
Denali	**49.3**	**37.9 - 64.1**					**47.4**	**1.6**	**NA**
Lake Chilchukabena	49.3	37.9 - 64.1					47.4	1.6	0.23
Glacier	**232.4**	**211.6 - 255.3**					**234.1**	**9.1**	**NA**
Lake McDonald	232.4	211.6 - 255.3					234.1	9.1	0.15
Glacier Bay	**90.2**	**79.1 - 102.9**			**102.3**	**19.6**			**0.49**
Falls Creek	56.4	50 - 63.6			56.4	10.9			0.22
North Skidmore Lake	113.7	102.3 - 126.4			113.7	22.1			0.18
Stonefly Lake	114.7	91.9 - 143.1			167.0	32.4			0.27
Grand Canyon	**76.0**	**66.1 - 87.5**			**101.2**	**9.6**			**0.54**
Bright Angel Creek	57.8	46.7 - 71.7			71.5	7.0			0.35
Havasu Creek	66.0	53.3 - 81.8			81.0	8.2			0.50
Shinumo Creek	108.9	89.1 - 133.2			178.8	18.0			0.28
Grand Teton	**32.6**	**28.3 - 37.6**			**31.3**	**4.5**			**0.28**
Death Canyon	22.9	21 - 25			25.1	3.7			0.10
Grizzly Bear Lake	52.1	40.9 - 66.4			42.4	6.3			0.40
Lake Solitude	29.0	24.1 - 34.9			28.8	4.3			0.29
Great Basin	**40.0**	**36.3 - 44.2**			**34.5**	**5.0**			**0.12**
Baker Lake	41.6	29.2 - 59.3			35.6	5.4			0.52
Lehman Creek	35.1	30.5 - 40.3			30.0	4.4			0.24
Snake Creek	44.7	40.4 - 49.4			38.3	5.6			0.16
Great Sand Dunes	**52.7**	**45.8 - 60.6**			**62.4**	**5.6**			**0.37**
Medano Lake	70.1	61.6 - 79.7			81.8	12.1			0.28
Sand Creek	38.8	34.6 - 43.5			47.6	4.8			0.21
Lake Clark	**229.3**	**192.8 - 272.8**					**201.0**	**2.9**	**0.57**
Lake Clark	365.2	327.4 - 407.4					365.2	9.2	0.31
Lake Kontrashibuna	204.0	147.9 - 281.4					204.0	7.3	0.41
Telaquana Lake	109.0	82.5 - 144					109.0	4.1	0.56

Park Site	Geometric Mean	95% CI[a]	50 mm[b]		200 mm[b]		400 mm[b]		CV
			LSM	SE	LSM	SE	LSM	SE	
Lassen Volcanic	**96.4**	**78.1 - 119**			**65.3**	**9.5**			**0.45**
Horseshoe Lake	180.7	132.3 - 246.9			84.8	12.5			0.29
Ridge Lake	111.3	89.9 - 137.9			95.4	14.0			0.39
Summit Lake	43.7	38.1 - 50.1			34.5	5.1			0.12
Mesa Verde	**74.9**	**59.9 - 93.7**	**74.9**	**2.9**					**NA**
Mancos River	74.9	59.9 - 93.7	74.9	2.9					0.30
Mount Rainier	**71.5**	**65.8 - 78.5**	**80.4**	**1.9**	**61.0**	**7.3**			**0.55**
Bench Lake	34.0	20.4 - 56.7			8.5	1.3			0.29
Golden Lake	66.6	47.7 - 93			193.2	28.5			0.14
Green Lake	66.2	58.3 - 75.2			77.3	11.9			0.12
Lake George	87.5	73.2 - 104.5	89.8	2.7					0.27
Louise Lake	86.1	63.2 - 117.3			105.9	16.2			0.19
Lower Deadwood Lake	82.9	65.5 - 104.8	50.6	2.0	77.9	8.0			
Lower Palisades Lake	116.3	103 - 131.4			92.9	13.6			0.21
MORA_1244	58.4	44 - 77.4			60.6	9.2			0.34
MORA_1614	227.4	157.5 - 328.2			97.8	14.9			0.30
MORA_230	121.2	86.7 - 169.4			80.7	12.0			0.32
MORA_234	66.2	53.1 - 82.5			87.4	12.9			0.29
MORA_583	19.2	14.4 - 25.5			16.4	2.5			0.46
MORA_LH15	66.4	51.1 - 86.2			62.5	9.2			0.36
Mowich Lake	97.2	72.9 - 129.6	114.1	5.6					0.17
Reflection Lake	80.8	62.3 - 104.9			101.0	14.8			0.44
Snow Lake	37.3	30.4 - 45.9			33.3	4.8			0.37
Upper Deadwood Lake	47.0	33.5 - 66.1			42.9	4.6			0.36
North Cascades	**54.9**	**46.7 - 64.4**			**73.3**	**7.2**			**0.45**
George Lake	44.1	33.5 - 58			54.1	5.6			0.34
Middle Blum Lake	62.2	46.3 - 83.5			118.5	17.5			0.36
Upper Wilcox Lake	56.2	41.8 - 75.5			61.5	9.1			0.18
Olympic	**85.0**	**80 - 90.3**			**109.7**	**12.1**			**0.60**
Gladys Lake	83.5	75.5 - 92.4			71.5	10.4			0.28
Hagen Lake	93.5	78.1 - 111.9			109.1	16.1			0.30
Hoh Lake	125.7	104.7 - 150.9			253.0	37.3			0.26
Sun Up Lake	85.2	79.1 - 91.7			99.4	14.5			0.19
Upper Lena Lake	66.1	58.9 - 74.1			81.1	8.0			0.27
Rocky Mountain	**66.1**	**61.4 - 71.1**			**54.8**	**6.3**			**0.43**
Black Lake	54.4	45.7 - 64.8			46.6	6.9			0.31
Colorado River	118.0	104.3 - 133.6			100.4	10.6			0.40
Fall River	106.2	83.3 - 135.5			59.3	6.3			0.43
Fern Lake	59.1	46.4 - 75.3			65.3	9.6			0.35
Fourth Lake.	70.4	58.8 - 84.3			71.6	10.6			0.27
Haynach Lake	19.8	15.9 - 24.5			19.4	2.9			0.26
Lake Haiyaha	18.5	15.9 - 21.5			21.6	3.2			0.26
Lake Louise	56.5	48.7 - 65.5			65.9	9.7			0.25
Lake Nanita	70.5	55 - 90.4			80.0	11.7			0.34
Lone Pine Lake	57.8	50.2 - 66.5			49.5	7.3			0.26
Mills Lake	87.5	68.5 - 111.9			94.0	9.5			0.37
Mirror Lake	121.2	86.2 - 170.5			102.4	14.9			0.36

Park Site	Geometric Mean	95% CI	50 mm[b]		200 mm[b]		400 mm[b]		CV
			LSM	SE	LSM	SE	LSM	SE	
Rocky Mountain cont.									
Poudre Lake	82.6	70.9 - 96.2			70.8	10.3			0.50
Sky Pond	30.7	23.2 - 40.6			21.4	3.2			0.30
Spruce Lake	89.3	69.7 - 114.4			97.5	14.4			0.30
Ten Lake Park	68.3	57.5 - 81			63.2	9.4			0.28
The Loch	38.9	27.1 - 56			38.6	5.7			0.82
Upper Hutcheson Lake	30.8	28 - 33.8			35.9	5.3			0.16
Ypsilon Lake	62.3	51.6 - 75.3			61.7	9.0			0.45
Sequoia - Kings Canyon	**43.8**	**39.1 - 49**			**69.5**	**6.3**			**0.38**
Bench Lake.	21.7	18.1 - 26.1			30.3	4.5			0.32
Center Basin Lake	67.0	60 - 74.9			207.3	39.8			0.28
Kern Point Lake	43.5	37.2 - 50.9			71.4	7.0			0.24
Lake 10310	24.9	20.1 - 30.9			52.1	7.7			0.41
Wrangell-St. Elias	**107.9**	**87.4 - 133.1**			**98.2**	**9.4**	**278.8**	**7.4**	**0.57**
Copper Lake	91.7	73.4 - 114.5			147.4	14.5	242.0	9.8	0.24
Summit Lake	53.3	48.5 - 58.5			65.4	6.6			0.18
Tanada Lake	416.6	358.4 - 484.2					321.2	13.0	0.19
Yellowstone	**101.2**	**92.7 - 110.5**			**119.8**	**10.2**	**116.0**	**4.3**	**0.23**
Beula Lake	107.1	95.5 - 120.1			111.1	16.4			0.18
Grebe Lake	110.5	94.2 - 129.7			168.8	16.4			0.19
Lewis Lake	69.2	56.5 - 84.9			92.3	10.1			0.25
Yellowstone Lake	108.9	92.8 - 127.7			119.3	17.6	116.0	4.3	
Yosemite	**82.1**	**57.5 - 117.2**			**70.0**	**10.2**			**0.86**
Mildred Lake	174.4	115.1 - 264.1			142.4	21.0			0.58
Spillway Lake	38.7	32.3 - 46.2			34.4	5.1			0.31
Zion	**241.5**	**209.7 - 278.2**	**242.5**	**5.4**					**0.57**
E. Fork Virgin River	234.9	180 - 306.5	236.8	7.4					0.29
N. Fork Virgin River	248.3	215.8 - 285.7	248.3	7.7					0.32

Table 4. Proportion of fish with wet weight mercury concentrations exceeding toxicity benchmarks from 86 sites in 21 western national parks in the Western United States.

[Comparisons to fish (no observed effects residue [NOER] = 200 ng/g, lowest observed effects residue [LOER] = 300 ng/g) and bird (high sensitivity = 90 ng/g, moderate sensitivity = 180 ng/g, low sensitivity = 270 ng/g) benchmarks were made using whole-body concentrations whereas comparisons to human consumption (unlimited consumption = 50 ng/g, EPA criterion = 300 ng/g, no consumption = 950 ng/g) benchmarks used concentrations in axial muscle tissue]

Park	Fish Toxicity		Bird Toxicity			Human Consumption		
Site	NOER	LOER	High Sens.	Moderate Sens.	Low Sens.	Unlimited Consumption	EPA Criterion	No Consumption
Among all parks	5	2	35	12	5	68	4	1
Capitol Reef	49	22	98	56	33	NA	NA	NA
Fremont River #1	67	33	100	80	60	NA	NA	NA
Fremont River #4	20	7	93	27	7	NA	NA	NA
Fremont River #7	60	27	100	60	33	NA	NA	NA
Crater Lake	--	--	--	--	--	19	--	--
Crater Lake	--	--	--	--	--	19	--	--
Denali	--	--	--	--	--	59	--	--
Lake Chilchukabena	--	--	--	--	--	59	--	--
Glacier	--	--	100	--	--	100	--	--
Lake McDonald	--	--	100	--	--	100	--	--
Glacier Bay	--	--	18	--	--	87	--	--
Falls Creek	--	--	--	--	--	60	--	--
North Skidmore Lake	--	--	20	--	--	100	--	--
Stonefly Lake	--	--	33	--	--	100	--	--
Grand Canyon	--	--	10	--	--	79	--	--
Bright Angel Creek	--	--	--	--	--	58	--	--
Havasu Creek	--	--	7	--	--	73	--	--
Shinumo Creek	--	--	20	--	--	100	--	--
Grand Teton	--	--	--	---	--	18	--	--
Death Canyon	--	--	--	--	--	--	--	--
Grizzly Bear Lake	--	--	--	--	--	47	--	--
Lake Solitude	--	--	--	--	--	7	--	--
Great Basin	--	--	--	--	--	18	--	--
Baker Lake	--	--	--	--	--	33	--	--
Lehman Creek	--	--	--	--	--	7	--	--
Snake Creek	--	--	--	--	--	20	--	--

Park / Site	Fish Toxicity		Bird Toxicity			Human Consumption		
	NOER	LOER	High Sens.	Moderate Sens.	Low Sens.	Unlimited Consumption	EPA Criterion	No Consumption
Great Sand Dunes	--	--	--	--	--	59	--	--
Medano Lake	--	--	--	--	--	100	--	--
Sand Creek	--	--	--	--	--	14	--	--
Lake Clark	31	7	76	42	10	98	41	--
Lake Clark	54	14	100	79	21	100	75	--
Lake Kontrashibuna	19	--	81	19	--	94	19	--
Telaquana Lake	--	--	27	--	--	100	--	--
Lassen Volcanic	2	--	40	2	2	72	2	--
Horseshoe Lake	7	--	87	7	7	93	7	--
Ridge Lake	--	--	35	--	--	100	--	--
Summit Lake	--	--	--	--	--	20	--	--
Mesa Verde	--	--	--	--	--	NA	NA	NA
Mancos River	--	--	--	--	--	NA	NA	NA
Mount Rainier	1	--	15	2	--	72	2	--
Bench Lake	--	--	--	--	--	17	--	--
Golden Lake	--	--	19	--	--	56	6	--
Green Lake	--	--	--	--	--	100	--	--
Lake George	--	--	6	--	--	NA	NA	NA
Louise Lake	--	--	--	--	--	100	--	--
Lower Deadwood Lake	--	--	18	--	--	94	--	--
Lower Palisades Lake	--	--	21	--	--	100	--	--
MORA_1244	--	--	--	--	--	57	--	--
MORA_1614	29	--	100	29	--	100	29	--
MORA_230	--	--	55	--	--	100	--	--
MORA_234	--	--	7	--	--	73	--	--
MORA_583	--	--	--	--	--	--	--	--
MORA_LH15	--	--	7	--	--	64	--	--
Mowich Lake	--	--	11	--	--	NA	NA	NA
Reflection Lake	--	--	19	5	--	71	5	--
Snow Lake	--	--	--	--	--	27	--	--
Upper Deadwood Lake	--	--	--	--	--	29	--	--
North Cascades	--	--	5			51	--	--
George Lake	--	--	--	--	--	40	--	--
Middle Blum Lake	--	--	7	--	--	53	--	--
Upper Wilcox Lake	--	--	8	--	--	58	--	--

Park / Site	Fish Toxicity		Bird Toxicity			Human Consumption		
	NOER	LOER	High Sens.	Moderate Sens.	Low Sens.	Unlimited Consumption	EPA Criterion	No Consumption
Olympic	--	--	6			94	--	--
Gladys Lake	--	--	3	--	--	100	--	--
Hagen Lake	--	--	7	--	--	100	--	--
Hoh Lake	--	--	33	--	--	100	--	--
Sun Up Lake	--	--	--	--	--	100	--	--
Upper Lena Lake	--	--	--	--	--	74	--	--
		--				--		
Rocky Mountain	2	--	15	3	1	66	3	--
Black Lake	--	--	--	--	--	60	--	--
Colorado River	--	--	28	3	--	100	3	--
Fall River	10	3	33	10	5	80	10	--
Fern Lake	--	--	--	--	--	80	--	--
Fourth Lake	--	--	--	--	--	87	--	--
Haynach Lake	--	--	--	--	--	--	--	--
Lake Haiyaha	--	--	--	--	--	--	--	--
Lake Louise	--	--	--	--	--	57	--	--
Lake Nanita	--	--	17	--	--	70	--	--
Lone Pine Lake	--	--	--	--	--	71	--	--
Mills Lake	--	--	13	--	--	80	--	--
Mirror Lake	10	--	57	17	--	77	17	--
Poudre Lake	--	--	17	--	--	100	--	--
Sky Pond	--	--	--	--	--	13	--	--
Spruce Lake	--	--	20	--	--	87	--	--
Ten Lake Park	--	--	--	--	--	93	--	--
The Loch	--	--	--	--	--	27	--	--
Upper Hutcheson Lake	--	--	--	--	--	--	--	--
Ypsilon Lake	--	--	10	--	--	60	--	--
Sequoia - Kings Canyon	--	--	--	--	--	46	--	--
Bench Lake	--	--	--	--	--	--	--	--
Center Basin Lake	--	--	--	--	--	73	--	--
Kern Point Lake	--	--	--	--	--	43	--	--
Lake 10310	--	--	--	--	--	13	--	--
Wrangell-St. Elias	16	4	39	18	7	76	18	--
Copper Lake	--	--	35	5	--	74	5	--
Summit Lake	--	--	--	--	--	60	--	--
Tanada Lake	85	23	100	85	38	100	85	--
Yellowstone	--	--	**20**	**1**	--	**94**	**1**	--
Beula Lake	--	--	7	--	--	100	--	--
Grebe Lake	--	--	30	--	--	97	--	--
Lewis Lake	--	--	7	--	--	80	--	--
Yellowstone Lake	--	--	23	3	--	97	3	--

Park / Site	Fish Toxicity		Bird Toxicity			Human Consumption		
	NOER	LOER	High Sens.	Moderate Sens.	Low Sens.	Unlimited Consumption	EPA Criterion	No Consumption
Yosemite	**7**	**3**	**27**	**7**	**3**	**60**	**7**	**3**
Mildred Lake	13	7	53	13	7	100	13	7
Spillway Lake	--	--	--	--	--	20	--	--
Zion	**20**	**3**	**90**	**27**	**3**	**NA**	**NA**	**NA**
E. Fork Virgin River	30	--	80	40	--	NA	NA	NA
N. Fork Virgin River	7	7	100	13	7	NA	NA	NA

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-133:
High Levels of Mercury in Fish at Hoh Lake Article



Glacier-fed Hoh Lake

High levels of mercury found in fish at Olympic National Park's Hoh Lake

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Tuesday, May 27, 2014 7:11pm | NEWS

Peninsula Daily News and news services

PORT ANGELES — High levels of mercury have been found in fish from a lake in Olympic National Park and in remote areas of other Western national parks, proving that even the most isolated lakes and streams in the U.S. aren't immune to mercury pollution.

The finding was included in a recently published study by the U.S. Geological Survey and National Park Service.

But overall, the report had fairly good news for sport anglers.

Researchers said that most fish they caught had "acceptable" mercury concentrations below the U.S. Environmental Protection Agency's fish t[illegible] criterion for safe human consumption.

But 4 percent exceeded healthy levels — including those from one of five lakes sampled in Olympic where mercury, a cumulative neurotoxin that can cause brain damage, approached levels unsafe for humans and fish-eating birds.

Hoh Lake was the only spot sampled in Washington's three national parks — Olympic, Mount Rainier and North Cascades — where the study found fish "are likely to approach or exceed the Environmental Protection Agency criterion for protection of human health" and for "reproductive impairment" of fish-eating birds.

The Geological Survey and National Park Service don't regulate health guidelines, but they are working with officials in Washington and the nine other states studied on possible fish consumption advisories.

Western parks were selected because of the significant role atmospheric mercury plays in remote places, and the lack of broad-scale assessments on mercury in fish in remote areas of the West, said Colleen Flanagan Pritz, a Park Service ecologist in Denver and coauthor of the study.

While previous studies documented mercury at the Olympic and Mount Rainier parks and other places in the West, this latest study "is a wake-up call," Flanagan Pritz said.

"We need to see fewer contaminants in park ecosystems, especially contaminants like mercury where concentrations in fish challenge the very mission of the national parks to leave wild life unimpaired for future generations."

Olympic National Park fish were sampled from five lakes — Gladys, Hagen, Hoh, Sun Up and Upper Lena lakes.

Researchers took samples from rainbow, cutthroat and brook trout.

Samples from the five lakes showed mercury concentrations averaging 85 nanograms per gram wet weight, slightly higher than the mean for the study.

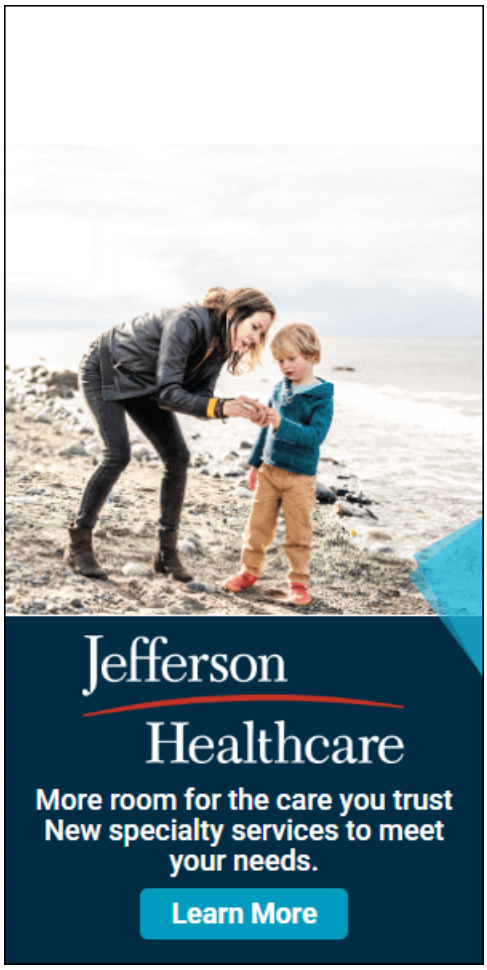
Size-adjusted concentrations at Hoh Lake were 253 ng/g ww. The EPA's human risk threshold is 300 ng/g ww.

At the low end of the spectrum was Gladys Lake, with a concentration of 71.5 ng/g ww.

Hagen was 109.1 ng/g ww; Sun Up, 99.4 ng/g ww; Upper Lena, 81.1 ng/g ww.

The National Park Service has blamed the Centralia Big Hanaford power plant in Lewis County, 55 miles from the southern borders of Olympic National Park, for mercury emissions as well as causing serious haze in the park.

[illegible] major coal-fired power plant supplemented with newer natural-gas-fired units.



Concerned about emissions of nitrogen oxide, particulate matter, mercury and sulfur dioxide, state and federal regulators in early 2011 struck a deal with the plant's owners that will result in both coal boilers being shut down by 2025.

Mercury is also believed to arrive in Washington state from pollution blown across the Pacific Ocean from coal-fired industries in China.

In two Alaskan parks, the average level of mercury in fish found bypassed the federal standard for human consumption.

In addition to Hoh Lake, the amounts of mercury also exceeded healthy levels at parks in California, Colorado and Wyoming, the study found.

Generally, the older and larger the fish, the more mercury they contain.

The fish study was the first of its kind to incorporate information from remote places at 21 national parks in 10 western states.

From 2008-2012, researchers sampled 1,486 fish from 16 species from 86 individual sites in the parks.

High mercury concentrations in birds, mammals and fish can result in reduced foraging efficiency, survival, and reproductive success.

Mercury concentrations in fish exceeded the most conservative fish toxicity benchmark at 15 percent of all sites, and levels exceeded the most sensitive health benchmark for fish-eating birds at 52 percent of all sites.

There were three sites in sampled in North Cascades National Park.

Results showed the mean mercury concentration below the average of all fish sampled in the study.

After standardizing the fish to 200 mm in length, the mean mercury concentration was 73.3 nanograms per gram wet weight.

At Mount Rainier, fish were sampled at 17 sites.

The average mercury concentration was 71.5 ng/g ww, similar to the studywide mean for all the fish in the study.

When adjusted to the 200 mm standardized size, concentrations ranged from 8.5-193.2 ng/g ww.

That large variation "emphasizes the need to sample from multiple locations in order to accurately characterize mercury risk to park resources as a whole," the report said.

Among the most widespread contaminants in the world, mercury is distributed globally from natural sources such as volcanic eruptions and from human sources such as burning fossil fuels in power plants.

Mercury is distributed at local or regional scales as a result of current and historic mining activities, the report said. These human activities have increased levels of atmospheric mercury at least threefold during the past 150 years, the researchers wrote.

Mercury, whether naturally occurring or in pollution, easily enters the food chain.

According to the Centers for Disease Control and Prevention, exposure to high levels of mercury in humans can damage the brain, kidneys and a developing fetus. Pregnant women and young children are particularly sensitive to mercury.

In birds that eat fish, the effects of mercury can range from reduced nest success rates – a bird might not return to a nest to incubate its eggs – and reduced ability to forage.

In fish, there are levels where changes in behavior are noticed, while higher levels could be lethal.

The full U.S. Geological Survey and National Park Service report is available at http://tinyurl.com/natparkfish.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-134:
Southwest Clean Air Agency Notice of Violation No. 10642

EXHIBIT 11-14

SWCAA
Southwest Clean Air Agency

NOTICE OF VIOLATION
No. 10642

5101 NE 82nd Avenue, Suite 102, Vancouver WA 98662 | 360-574-3058 / 800-633-0709 | www.swcleanair.gov

DATE OF VIOLATION:	TIME OF VIOLATION: *(if applicable)*
October 23, 2025	09:25

LOCATION OF VIOLATION:
Flyash Unloading Baghouse - 913 Big Hanaford Road, Centralia, WA 98531

RESPONSIBLE PARTY / PROPERTY OWNER / FACILITY NAME:
TransAlta Centralia Generation, LLc

MAILING ADDRESS:
913 Big Hanaford Road, Centralia, WA 98531

PHONE NUMBER:	EMAIL ADDRESS:	SWCAA ID:
360-330-2306	Sam_Bocook@transalta.com	754

Description of Violation(s)

IN VIOLATION OF (REGULATION/PERMIT/ORDER):	DID CAUSE OR ALLOW:
Condition 2 of ADP 12-3016, Req.-79 of AOP SW98-8-R5-A SWCAA 400-040(1), Req.-1 of AOP SW98-8-R5-A SWCAA 400-116(2)	Failure to maintain the Fly Ash Weigh Bin Baghouse properly, resulting in excess visible emissions.

DETAILS / EVIDENCE:

On October 23, 2025 Abraham Apfel and I visited TransAlta Centralia Generation for an unannounced inspection. Before entering the plant we drove past on Big Hanaford Road and observed a dense plume of ash from the Fly Ash Weigh Bin Baghouse and took a photograph and video. No trucks were being loading at the time. When I returned for a follow-up visit on November 4, 2025 the issue had been resolved and I spoke to maintenance personell who indicated the filters had been "plugged". This does not explain the excess emissions, but no further explanation was available. During an inspection on September 28, 2024 visible emissions could be seen from the fly ash weigh bin baghouse when viewed from the elevator to the west, but not from a legal Method 9 observation point. Fly ash loading was not occurring at the time. TransAlta reportedly replaced the filter cartridges in the unit later the same day to correct the problem.

Notice of Violation issued by

SWCAA REPRESENTATIVE:	DATE ISSUED:
Clint Lamoreaux	December 2, 2025
PHONE NUMBER:	**EMAIL ADDRESS:**
360-574-3058 ext. 131	clint@swcleanair.gov

Delivery Method

☐ IN PERSON
☒ USPS CERTIFIED MAIL
☐ ELECTRONIC MAIL

IF DELIVERED IN PERSON
NAME / TITLE OF RECIPIENT:

(SIGNING NOTICE DOES NOT CONSTITUTE AN ADMISSION OF GUILT)

Important Information – Please Read

You may provide additional information for the Southwest Clean Air Agency (SWCAA) to consider when addressing the above referenced alleged violation(s). You are also welcome to provide evidence of any corrective actions you have taken, or will take, as evidence of prompt and effective corrective actions may reduce your penalty if a penalty is assessed. If you wish to provide additional information, or schedule a meeting with the Agency, please do so within thirty (30) days of receiving this notice. Depending on the circumstances, you typically will receive one of the following: (1) Notice of Corrective Order (NCO), a (2) Notice of Civil Penalty (NCP) or (3) a Notice of Civil Penalty and Corrective Order (NCPCO), unless the information you submit to SWCAA indicates that a violation did not occur. An NCO orders prescribed corrective actions but assesses no civil penalty. An NCP assesses a penalty not to exceed $17,000 for each day of non-compliance. An NCPCO orders both corrective actions and a civil penalty. A civil penalty may be issued no sooner than thirty (30) days after your receipt of this Notice of Violation. For any of these actions you will receive further notification from the Southwest Clean Air Agency. Civil penalties and corrective orders may be appealed to the Pollution Control Hearings Board (PCHB) within thirty (30) days of the date of receipt of an NCO, NCP or NCPCO issued by SWCAA. For more information about appeals see RCW 43.21B, RCW 70A.15, and WAC 371-08 or visit https://eluho.wa.gov/boards/pollution- control-hearings-board.

SWCAA NOTICE OF VIOLATION ENFORCEMENT PROCESS

Step 1	Step 2	Step 3	Step 4	Step 5
Notice of Violation (NOV) issued by SWCAA for permit and/or regulation-based violations recorded by the Agency.	Within thirty (30) days of receipt of the NOV, provide SWCAA with information to show that the violation did not occur, or that you were not responsible for the violation recorded by the Agency.	Unless you have shown that a violation did not occur, or that you were not responsible for the violation, and after at least thirty (30) days have passed from the date the NOV was received, SWCAA will typically issue a Notice of Corrective Order (NCO)[1], a Notice of Civil Penalty (NCP)[2] or a Notice of Civil Penalty and Corrective Order (NCPCO)[3].	Within thirty (30) days of receipt of an NCO, NCP or NCPCO issued to you by SWCAA, you may request remission or mitigation, or appeal the civil penalties and/ or corrective orders to the Pollution Control Hearings Board (PCHB).	Unless you have been provided with relief by PCHB, remit any penalties to SWCAA and/or complete the prescribed corrective actions within the timelines provided in the NCO, NCP or NCPCO letter.

[1] *Notice of Corrective Order (NCO) - order prescribes corrective actions but no civil penalty.*

[2] *Notice of Civil Penalty (NCP) - assesses a penalty not to exceed $17,000 for each day of non-compliance.*

[3] *Notice of Civil Penalty and Corrective Order (NCPCO) - assesses both a penalty, not to exceed $17,000 for each day of non-compliance, as well as an order prescribing corrective actions.*

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-135:
Southwest Clean Air Agency Notice of Violation No. 10643

EXHIBIT 11-15

SWCAA
Southwest Clean Air Agency

NOTICE OF VIOLATION
No. 10643

5101 NE 82nd Avenue, Suite 102, Vancouver WA 98662 | 360-574-3058 / 800-633-0709 | www.swcleanair.gov

DATE OF VIOLATION:	TIME OF VIOLATION: *(if applicable)*
1/11/25, 3/4/25, 6/6/25, 6/11/25, 8/26/2025	Various

LOCATION OF VIOLATION:
Unit #2 - 913 Big Hanaford Road, Centralia, WA 98531

RESPONSIBLE PARTY / PROPERTY OWNER / FACILITY NAME:
TransAlta Centralia Generation, LLC

MAILING ADDRESS:
913 Big Hanaford Road, Centralia, WA 98531

PHONE NUMBER:	EMAIL ADDRESS:	SWCAA ID:
360-330-2306	Sam_Bocook@transalta.com	754

Description of Violation(s)

IN VIOLATION OF (REGULATION/PERMIT/ORDER):	DID CAUSE OR ALLOW:
40 CFR 63.10042 definition of "Startup" and Table 3, Section 3 of 40 CFR 63 Subpart UUUUU SWCAA 400-075	Firing of coal during startup before fully engaging the wet scrubber.

DETAILS / EVIDENCE:

Individual startup reports and quarterly reports submitted in accordance with 40 CFR 63 Subpart UUUUU detail when the flue gas desulfurization (FGD) system (scrubber) was online and when coal firing began.

Effective July 8, 2024 EPA set a deadline (January 2, 2025) by which facilities could no longer use the second definition of "startup" in 40 CFR 63.10042. The effect of this change was that the scrubber must be online before coal is fired during startup.

Notice of Violation issued by

SWCAA REPRESENTATIVE:	DATE ISSUED:
Clint Lamoreaux	December 16, 2025
PHONE NUMBER:	EMAIL ADDRESS:
360-574-3058 ext. 131	clint@swcleanair.gov

Delivery Method

☐ IN PERSON
☒ USPS CERTIFIED MAIL
☐ ELECTRONIC MAIL

IF DELIVERED IN PERSON
NAME / TITLE OF RECIPIENT:

(SIGNING NOTICE DOES NOT CONSTITUTE AN ADMISSION OF GUILT)

Important Information – Please Read

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