BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-46:
R Street Institute Commentary: DOE "Zombies" Are Eating Competitive Power Mark

REAL SOLUTIONS

Low-Energy Fridays: DOE "Zombies" Are Eating Competitive Power Markets

BY MICHAEL GIBERSON

ISSUES: ELECTRICITY POLICY, ENERGY AND ENVIRONMENT

NOV 13, 2025

This past May, the U.S. Department of Energy (DOE) used emergency authority to stop two scheduled power plant retirements. As we explained in July, these emergency orders are not a good way to boost grid reliability. That's not the only problem, though—the DOE's emergency orders also threaten to undermine competition in regional power markets.

The case invoked Section 202(c) of the Federal Power Act, which limits most orders to just 90 days. The DOE used this law to block the coal-fired J.H. Campbell Power Plant in Michigan and two units at the gas- and oil-fired Eddystone Generation Station in Pennsylvania from retiring. When those 90-day orders expired in August, the DOE issued new orders to keep the plants online. When these orders expire later in November, the DOE is expected to order the plants to stay online for *another* 90 days. Both currently operate with a safety net: If they lose money, the law makes area consumers cover those losses. And with losses covered no matter what, the plants have little reason to run efficiently. The result isn't grid reliability—it's creeping zombification of the market.

Markets require profits *and* losses to steer investment where it's needed (and away from where it's not). When a unit can't cover its costs at market prices, it should retire. When older, inefficient plants exit, space opens on the grid and in the market for better resources to jump in. Prices may initially rise, but consumers benefit in the end as competition grinds down average costs. Serial "emergency" orders break the economic feedback loop and undermine competitive forces.

The DOE's decision to keep two fossil-fueled power plants running raised speculation that the administration would block any fossil-fueled plant from retirement. However, a New Hampshire coal unit retired in October without federal intervention. That's good, because a plant that doesn't contribute to reliability and energy supplies at a competitive price *should* retire. But the lack of clear policy heightens uncertainty.

The economic damage shows up in three places:

- **Crowding out.** When zombie power plants are ordered to stay in the market, customers are stuck with the bill from any losses. Market revenues that would support efficient resources get skimmed by units the market has already rejected. The effect is subtle but important: Energy market prices flatten, clean and firm resources see less upside in tight hours, and generation turnover slows.

- **Planning.** Reliability planning depends on credible schedules—retirements that can be believed, new power plants that can be counted, and rules that don't change unnecessarily. A plant yo-yoing between "retired," "ordered to run," and "maybe extended" in 90-day increments can't fit into long-run reliability plans.
- **Policy-driven uncertainty.** States and stakeholders are suing the DOE over the emergency orders because the law is being employed in a manner different from what Congress intended. The DOE has not articulated a clear policy for how they will use their authority in the future, which leaves plant owners and potential investors in the dark.

Emergency orders do have their place. If a hurricane hits, fuel freezes, or a wildfire takes out a major power line, use 202(c) for the days or weeks necessary and then stand down. Utilities regularly ask for these emergency orders when they need them. The difference with zombie plant orders is that neither the plant owners nor the grid operators responsible for reliability in their regions requested them.

Nothing in this discussion denies reality—demand for electricity is rising, interconnection queues are clogged, and grid operators face tough winters and hot summers. The way forward is in policies that make better use of the existing grid, drive economical additions to transmission infrastructure, and let market forces drive power plant entry *and* exit. Competitive power markets are not responsible for rising electricity rates; in fact, a recent study pointed to increased spending on transmission and distribution wires as key factors in driving up customer rates.

Should the DOE continue to undermine market competition, consumers may get hit with the double-whammy of rising energy costs and rising infrastructure spending. Zombification of the electricity industry is no way to support a reliable, efficient power system.

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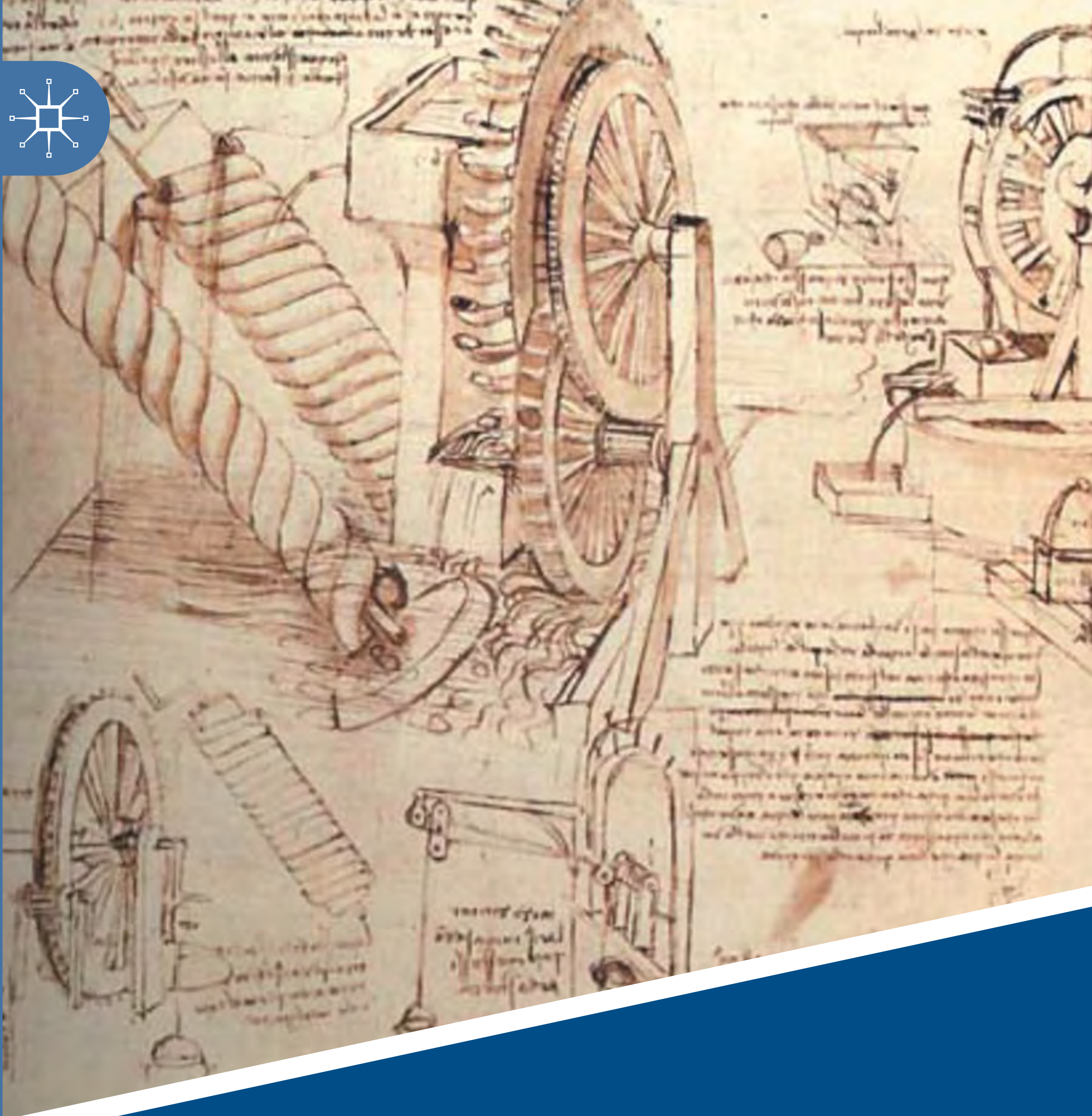
Exhibit 2-47:
Palgrave Handbook



The Palgrave Handbook of International Energy Economics

Edited by Manfred Hafner · Giacomo Luciani

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rotating standby state through the advanced control system, and the gas turbine is quickly started with load, and the power is immediately transmitted to the power grid.

3.4 Location

Coal power generation location is more restrictive compared to other technologies because coal is a solid and its transport cost is high, while its combustion efficiency is lower than for other technologies. Usually coal plants are located near coal mines and the choice of different means of transport will affect the location of the plant area as well as the size and form of the required land plot, especially for a large power plant. The transportation mode should allow for large volume, low freight, high speed, and flexibility, which will make the location of coal plant all the more difficult.

On the contrary, oil is easy to transport with multiple transportation options including by pipeline and by ship; therefore, oil-fired plants are usually located in coastal areas. A gas-fired power plant is characterized by little land occupation and is very suitable for countries and areas with dense population and scarce land resources. Compared with coal-fired power plants, gas power generation equipment is more compact and does not occupy a large area. Besides, it consumes one-third of the water needed for a coal-fired power plant.

3.5 Expected Service Life

Thermal power plants are designed for an economic lifetime of 30 to 40 years, but some plants have been also used beyond their design life in certain areas. The critical components are the boiler and the turbine. The operation of thermal power generation is faced with both tangible and intangible aging processes. Tangible or physical aging refers to the equipment operating under high pressure and temperature, and bearing mechanical stress, resulting in physical and chemical changes, such as wear, creep, corrosion, and so on, gradually making the equipment unable to continue operating safely under the required design parameters. Invisible aging refers to technological progress. The advent of more efficient or less labor-intensive production equipment means that older equipment will operate under less and less economic conditions. The physical aging of some equipment (such as condenser copper pipes, heater pipes, boiler heating surface pipes, turbine blades, furnace walls, etc.) can be removed during overhaul. However, it is often the aging of these important equipment components that determines the technical and consequently economic lifetime of thermal power plants. Operating experience shows that the service life of equipment operating under 450 °C is between 40 and 50 years. For equipment operating at temperatures above 450 °C, the operating hours could even be reduced to 100,000 hours.

Both gas and steam turbines are devices that drive the rotor to rotate at high speed through high-pressure gas with high temperature and humidity.

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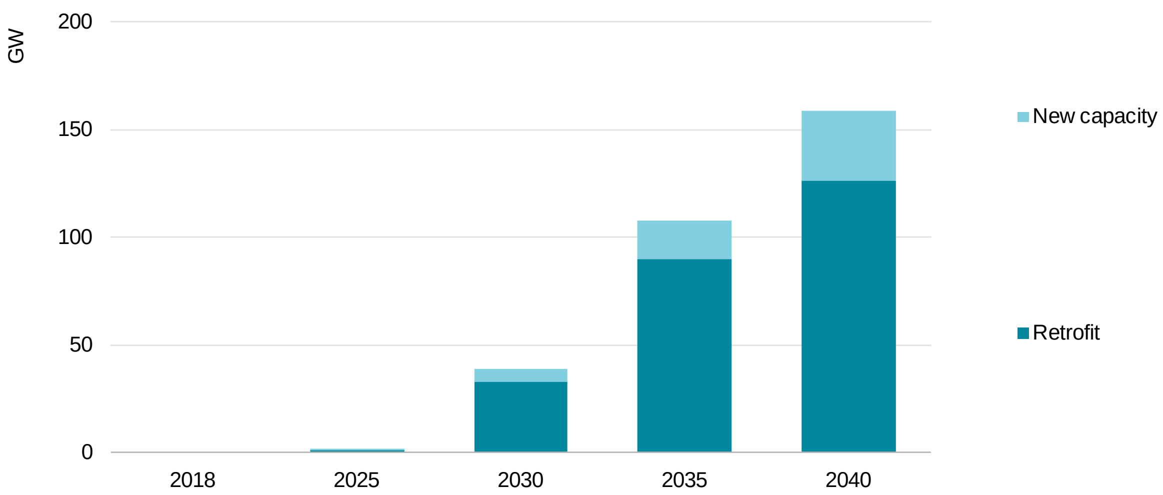
Exhibit 2-48:
IEA Report

The role of CCUS in low-carbon power systems

Without carbon capture, meeting climate goals would ultimately mean almost eliminating the use of fossil fuels for power.

In the Sustainable Development Scenario, 120 GW of existing coal-fired capacity is retrofitted with carbon capture by 2040, accounting for some 80% of the coal plants equipped with these technologies. More than 110 GW of these retrofits are in China, representing a capital investment of around USD 160 billion. A further 10 GW are in the United States. Without carbon capture available at scale in power, coal-fired power generation, and eventually also gas-fired generation, would need to be virtually eliminated to meet long-term climate goals, with significant early retirements and potential stranding of assets.

Figure 4 **Coal-fired power plants equipped with carbon capture in the Sustainable Development Scenario**



Source: IEA (2019), World Energy Outlook 2019.

Over 750 GW of existing coal plants reduce operations to cut emissions in this Scenario, limiting electricity production but still providing system adequacy and flexibility. About one-quarter of the existing fleet would be retired before reaching the typical 50-year lifespan. Shutdowns and reduced operating hours are likely to lead to balance sheet write-downs for some owners of existing facilities. Coal plant retirements also imply greater investment in other low-carbon sources of electricity and associated network infrastructure.

Carbon capture retrofits also play an important role for the gas-fired power plant fleet, which currently has an average age of only around 19 years. In the SDS 155 GW of natural gas-fired power plants are equipped with carbon capture, utilisation and

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Exhibit 2-49:
2011 BART Order

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY

IN THE MATTER OF AN ADMINISTRATIVE ORDER AGAINST: TransAlta Centralia Generation LLC	]]]]]	 FIRST REVISION: ORDER NO. 6426

TO: Mr. Bob Nelson,
TransAlta Centralia Generation LLC
913 Big Hanaford Road
Centralia, WA 98531

This is an Administrative Order requiring your company to comply with WAC 173-400-151 by taking the actions that are described below. Chapter 70.94 RCW authorizes the Washington State Department of Ecology's Air Quality Program (Ecology) to issue Administrative Orders to require compliance with the requirements of Chapter 70.94 RCW and regulations issued to implement it.

Ecology has determined that portions of your facility are subject to the provisions of the state visibility protection program (WAC 173-400-151), which is implemented consistent with the requirements of the federal visibility protection program (40 CFR Part 51, Subpart P). The rules require that the State determine what technologies and level of emission control constitute Best Available Retrofit Technology (BART) for the eligible emission units at your facility. The rules also require the installation and use of those emission controls on the BART-eligible emission units. The emission controls are to be installed as expeditiously as possible, but in no event may the State allow them to start operation later than five years after the State's Regional Haze SIP amendment is approved by the United States Environmental Protection Agency (EPA).

FINDINGS

A. The TransAlta Centralia Generation LLC ("TransAlta") Centralia Power Plant is a coal fired power plant larger than 750 MW output subject to BART. The power plant is comprised of 2 identical coal fired units referred to as BW21 and BW22.

B. BART emission limitations for sulfur dioxide and particulate matter were determined by the Environmental Protection Agency in 2003. The Centralia Power Plant's Operating Permit incorporates the BART emission limitations determined by EPA.

C. BART for nitrogen oxides at the Centralia Power Plant is based on:

a. Use of selective noncatalytic reduction (SNCR) for nitrogen oxides control.
b. Use of low NO_x burners with separated and close coupled over fire air systems (aka LNC3).
c. Use of a sub-bituminous Powder River Basin coal or other coal that will achieve similar emission rates.

d. Use and installation of additional boiler heat recovery equipment and boiler tube cleaning equipment to maximize the extraction of fuel energy into boiler steam.

D. RCW 80.80.040 was amended in 2011 (Chapter 180, Laws of 2011) adding greenhouse gas emission requirements applicable to this facility that reduce the remaining useful life of each coal fired unit at the plant to approximately 8 and 13 years, starting from June 2011. The greenhouse gas emission requirements are:

a. Amendments to Chapter 80.80, Revised Code of Washington passed in 2011 require both coal fired units at the Centralia Power Plant to comply with the greenhouse gas emission performance standard requirements of Revised Code of Washington 80.80.040. One unit is required to comply by December 31, 2020. The other unit is required to comply by December 31, 2025. The plant owner, the Governor's office, and environmental organizations anticipate that compliance with this requirement will be accomplished by decommissioning the units.
b. The requirement to meet the greenhouse gas emission performance standard does not apply if the Department of Ecology determines that a state or federal requirement requires the installation of selective catalytic reduction for Nitrogen oxides control on the coal units.

Additional information and analysis is available in the BART Determination Support Document for the Centralia Power Plant, by the Washington State Department of Ecology, November 2008 (revised April 2010 and May 2011); and the BART Analysis for the Centralia Power Plant, June 2008 and the BART Analysis Supplement, December 2008, and supplemental information dated March 2010; and Chapter 180, Laws of 2011.

YOU ARE ORDERED: To install and operate in accordance with the following conditions:

BART Emission Limitations

1. Nitrogen Oxides Emissions

1.1. Starting no later than the dates in Condition 1.1.1 and 1.1.2, emissions of nitrogen oxides from the two coal-fired utility steam generating units (known as BW21 and BW22) at the Centralia Power Plant are limited to a maximum of:

1.1.1. From the date of issuance of this Order, until 30 operating days after December 31, 2012, the nitrogen oxides emission limitation is 0.24 lb/MMBtu, 30 operating day rolling average, both units averaged together, including all emissions during unit start-up and shut-down.

1.1.2. Beginning on the 31st operating day after December 31, 2012, the nitrogen oxides emission limitation is 0.21 lb/MMBtu, 30 operating day rolling average, both units averaged together, including all emissions during unit start-up and shut-down.

1.1.3. The 30 day rolling average will be determined per Condition 7.

1.2. Beginning January 1, 2013, injection of ammonia or urea to control nitrogen oxides from a specific boiler must:

1.2.1. Commence when the flue gas at the point(s) of injection in the boiler has reached the minimum SNCR operating temperature as identified by the system vendor in the system specific operation manual.

1.2.2. End no sooner than the time coal is no longer introduced to the furnace of the boiler or the flue gas temperature at the injection point(s) is below the minimum SNCR operating temperature.

1.3. Compliance with the nitrogen oxides emission limitation will be determined by use of a continuous emission monitoring system meeting the requirements of 40 CFR Part 75.

1.4. Coal used is required to be a sub-bituminous coal from the Powder River Basin or other coal that will achieve similar emission rates.

1.5. Nitrogen oxides emission reduction through the use of SNCR will be optimized as required in Condition 5. At the conclusion of the SNCR optimization study, the nitrogen oxides emission limitation contained in Condition 1.1.2 may be revised based on the results of the SNCR optimization study.

2. Ammonia emissions

2.1. Starting no later than the date in Condition 2.2, emissions of ammonia from the two coal-fired utility steam generating units at the Centralia Power Plant are limited to a maximum of:

2.1.1. Starting on January 1, 2013, the ammonia emission limitation is 10 parts per million, dry volume (ppmdv) 30 operating day rolling average, both units averaged together.
EXCEPTION: During the portion of the optimization study directed by Condition 5.2.3.1, the ammonia emission limitation is 20 ppmdv daily average, both units averaged together.

2.1.2. In the event that during a given day, only one unit operated, the average of both units will be the calendar day average of the operating boiler. The emission rate of zero for the unit that did not operate must not be included in calculating the average emissions.

2.2. Determination of compliance with the 30 operating day rolling average for ammonia will commence at midnight on the end of the 30th operating day after January 1, 2013.

2.3. Ammonia emission resulting from the use of SNCR will be optimized as required in Condition 5. The ammonia emission limitation contained in Condition 2.1.1 may be revised based on the results of the SNCR optimization study.

Schedule for Compliance

3. Compliance with the 30 operating day rolling average nitrogen oxides limitations begin on the dates given in Condition 1.1.1 and 1.1.2. Compliance with the 30 operating day rolling average ammonia emission limitations begins on the date given in Condition 2.1.

4. Coal units BW21 and BW22 will permanently cease burning coal and be decommissioned as follows:

4.1. One coal fired unit must permanently cease burning coal no later than December 31, 2020.

4.2. The second coal fired unit must permanently cease burning coal no later than December 31, 2025.

4.3. Conditions 4.1 and 4.2 do not apply in the event the Department of Ecology determines as a requirement of state or federal law or regulation that the selective catalytic reduction technology must be installed on either coal fired unit.

Nitrogen Oxides and Ammonia Reduction Optimization

5. The operation of the selective noncatalytic reduction (SNCR) system for control of nitrogen oxides will be optimized to produce both the lowest nitrogen oxides emission rate and the lowest ammonia emission concentration possible at the same time.

5.1. The nitrogen oxides control system will be optimized to achieve both the lowest 30 operating day average pound nitrogen oxides/MMBtu emission rate and the lowest 30 day average concentration of ammonia in the flue gas that is reasonably achievable without significant adverse effect on mercury capture, boiler cleaning processes (aka soot blowing) or byproduct salability .

5.2. To achieve the goal of Condition 5.1, The owner of the Centralia Power Plant will:

5.2.1. Develop an SNCR optimization plan and submit it by April 30, 2013 to Ecology and the SWCAA for their joint review and acceptance.

5.2.1.1. A draft optimization plan will be submitted to Ecology and SWCAA by January 30, 2013 for their review and comment. Ecology and/or SWACAA will respond with written comments within 45 days of receipt of the draft optimization plan. If a request for a copy of this draft optimization plan is received, the agency receiving the request will provide the requester a copy of the draft optimization plan.

5.2.1.2. TransAlta will submit a final optimization plan reflecting all comments provided by Ecology and SWCAA. The plan must be submitted no later than April 30, 2013. The plan will be deemed to be accepted and the owner will immediately implement the plan if Ecology and/or SWCAA do not respond by May 30, 2013. If TransAlta, Ecology, or SWCAA receive a request for a copy of the final optimization plan, the entity receiving the request will provide a copy of the optimization plan to the requestor.

5.2.2. The optimization plan will:

5.2.2.1. Provide for all optimization testing to be complete and a report on the findings submitted to Ecology and SWCAA not later than December 31, 2014.

5.2.2.2. Identify the start and end dates of the optimization study.

5.2.2.3. Describe the optimization process to be followed, including:

5.2.2.3.1. The overall schedule.

5.2.2.3.2. The specific dates for each stage of the optimization program, especially the start and end dates of the testing to determine how low of a nitrogen oxides emission rate can be achieved per condition 5.2.3.1.

5.2.2.3.3. Whether testing will be done on only one boiler at a time or both together.

5.2.2.4. Identify acceptable maximum ammonia content of fly ash used for cement and gypsum used to produce wallboard, including the basis for those maximums.

5.2.2.5. Identify all additional flue gas monitoring that will be used to determine optimum urea or ammonia injection rates for maximum nitrogen oxides reduction.

5.2.2.6. Evaluate the effect of ammonia injection on mercury capture effectiveness, fly ash ammonia content, and gypsum product ammonia content. This includes a description of the sampling and analysis processes.

5.2.3. The focus of the optimization plan, is to determine :

5.2.3.1. The maximum nitrogen oxides reduction possible with an ammonia emission rate of up to 20 ppmdv, daily average, each unit individually;

5.2.3.2. The maximum nitrogen oxides reduction with which compliance can be reasonably achieved within an ammonia emission rate of 5 ppm; and

5.2.3.3. Determine the lowest nitrogen oxides emission rate reasonably achievable that coincides with the minimum ammonia emission rate.

5.2.3.4. The ability to achieve a nitrogen oxides emission rate of less than 0.19 lb/MMbtu, 30 operating day rolling average, each unit individually.

5.3. Ecology and SWCAA will review the optimization study report for 60 days. At the end of the 60 days the two agencies will either request TransAlta make changes to the report or accept the report in writing.

5.4. Within 90 days of receiving written acceptance of the optimization study report by Ecology and SWCAA, the plant operations and maintenance manual(s) will be amended to include the operating parameters reflecting the optimized ammonia or urea injection rates developed.

5.5. Revisions to this BART Order

5.5.1. Within 30 days of acceptance of the optimization study report by Ecology and SWCAA, TransAlta will submit a request to Ecology to revise the emission limits in Conditions 1.1.2 and 2.1.1 to reflect the results of the optimization.

5.5.2. Upon receipt of the request to revise the emission limits, or within 60 days of acceptance of the optimization report by Ecology and SWCAA, Ecology will proceed to revise the emission limitations in Conditions 1.1.2 and 2.1.1 to reflect the results of the optimization study. Other approval conditions, including this condition, may be revised based on the final emission limitations.

5.5.3. The nitrogen oxides limitation will not be raised above the level in Condition 1.1.2 as it existed on the date of issuance of this Revised Order.

5.5.4. The ammonia limitation will not be raised above the level in Condition 2.1.1 as it existed on the date of issuance of this Revised Order.

Monitoring and Recordkeeping Requirements

6. Ammonia:

6.1. Ammonia emissions for compliance will be monitored by means of periodic emissions testing utilizing Bay Area Air Quality Management District (BAAQMD) Method ST1B or Environmental Protection Agency Conditional Test Method 027 (CTM-027). The sampling point will be in the stack following the wet scrubber. Stack testing shall occur on the following frequency:

6.1.1. Testing shall occur once each calendar quarter, with no consecutive tests less than 80 or more than 110 calendar days apart.

6.1.2. If 3 consecutive tests are each less than the ammonia limitation, then the testing frequency reduces to once every 6 calendar months, provided the nitrogen oxides emission limit is complied with during the test.

6.1.3. If, after there are 3 consecutive tests less than the ammonia limitation, the next 2 consecutive tests are less than 50% of the ammonia emission limitation, then the testing frequency reduces to once annually, provided the nitrogen oxides emission limit is complied with during the tests.

6.1.4. If at any time there is a test showing emissions above the emission limitation, then the testing frequency reverts to quarterly until the requirements in Conditions 6.1.2 and 6.1.3 are met.

6.1.5. The ammonia concentration measured during the periodic emissions testing is the 30 operating day rolling average value used for compliance starting on the date of the completion of the test until the completion of the next required periodic emission test.

6.1.6. During the ammonia testing using BAAQMD Method ST1B (or CTM-027), the 30 rolling ammonia emission limit is to be treated as an hourly average for the purpose of Conditions 6.1. and 6.2.

6.2. For use as a routine indicator of compliance between the tests required in Condition 6.1, ammonia emissions will be estimated. The estimate will be based on a calculation which uses as inputs the reagent concentration and flow rate, a calculation or measurement of the uncontrolled nitrogen oxides rate, the continuous nitrogen oxides monitoring results measured in the stack, and other parameters as necessary.

6.3. At TransAlta's option, an ammonia continuous monitoring system may be used instead of periodic emissions tests. A continuous ammonia monitoring system used for compliance must meet the monitor location requirements contained in 40 CFR Part 60 Appendix B, Performance Specification 1 or 2, and the quality assurance and quality control requirements of 40 CFR Part 60 Appendix F as applicable.

7. Nitrogen oxides monitoring and averaging

7.1. For any hour in which coal is combusted in a unit, the owner/operator of each unit shall calculate the hourly nitrogen oxides concentration in lb/MMBtu at the CEMS installed in accordance with the requirements of 40 CFR Part 75. The 30-day average lb/MMBtu rate is calculated by summing the hourly emissions in pounds (unit lb/MMBtu times unit heat input) from all operating units and dividing that by the sum of the hourly heat inputs in million Btu for all operating units. At the end of each boiler operating day, the owner/operator shall calculate and record a new 30-day rolling average emission rate in lb/MMBtu from all valid hourly data for that boiler operating day and the previous 29 successive boiler operating days.

7.2.). An hourly average nitrogen oxides emission rate is valid only if the minimum number of data points, as specified in 40 CFR Part 75, is acquired as necessary to calculate nitrogen oxides emissions and heat rate.

7.3. Data reported to meet the requirements of this section shall not include data substituted using the missing data substitution procedures of subpart D of 40 CFR part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR part 75.

7.4. A boiler operating day is a 24-hour period between 12 midnight and the following midnight during which coal is combusted at any time in the boiler. It is not necessary for coal to be combusted for the entire 24-hour period.

8. Ammonia emission limitation compliance based on periodic stack sampling and parameter monitoring.

8.1. Compliance with the ammonia emission limitation is demonstrated by meeting the limitation during the stack testing period. The average of the 3 discrete sampling runs will be used to determine compliance with the ammonia emission limitation until the next periodic stack testing occurs.

8.2. During each periodic stack test on each boiler, the ammonia or urea reagent injection rate and the ammonia to nitrogen oxides ratio for each sampling run shall be determined, recorded and reported as part of the testing report.

8.3. During plant operation between periodic stack testing, compliance with the ammonia emission limitation will be indicated by:

8.3.1. Injecting ammonia or urea reagent at the injection rate for ammonia or urea reagent used during the most recent stack sampling at the appropriate operating rate; and

8.3.2. Meeting the nitrogen oxides emission limit.

9. Coal Quality Monitoring

9.1. Coal nitrogen and sulfur content will be determined by taking a sample of the coal from the transfer belts between the coal pile and coal silos. An alternate location that provides a sample representative of the coal fired by the boilers may be proposed to Ecology by TransAlta for approval for use.

9.2. A sample of coal for nitrogen and sulfur content analysis will be taken at least once per week when at least one coal fired boiler is in operation. The sample must be taken following ASTM Method D2234/D2234M-07.

9.3. Coal nitrogen and sulfur content will be determined using ASTM Method D3176-89 (as reapproved in 2002). Note, other ASTM methods related to sample collection and preparation may need to be followed in order to perform this test.

9.4. As an alternate to coal nitrogen and sulfur content testing at the plant, certified results of testing by the coal mine operator of coal actually sent to the Centralia Power Plant may be used. Testing frequency should be no less frequent than required above.

Reporting Requirements

10. A letter reporting of achievement of each compliance date in the schedule in Conditions 3 and 4 must be submitted to the Washington State Governor, Ecology, and SWCAA within 30 days of achieving the milestone.

11. Emissions above the emission limitations in this order due to malfunctions must, at a minimum, be documented in writing and submitted to SWCAA and Ecology with the emissions monitoring data per Condition 12. Additional recordkeeping and notifications related to excess emissions may also be required by SWCAA or Ecology regulation. Excess emissions that TransAlta believes are unavoidable must be documented as required in WAC 173-400-107 (or section 109 after that section is approved into the Washington SIP) and SWCAA's unavoidable excess emissions requirements.

12. Emission monitoring data will be reported to Ecology and to the SWCAA.

12.1. Continuous emission monitoring reports will be submitted within 30 days after the end of each calendar quarter. The reports must contain the following information:

12.1.1. The 30 operating day rolling average pound nitrogen oxides/MMBtu for each operating day in the reporting period. The 30 day rolling average nitrogen oxides emission rate shall be reported in units of lb/MMBtu, utilizing at least 2 significant figures;

12.1.2. The cumulative short tons of nitrogen oxides per unit and combined that has been emitted during the current calendar year. The cumulative tons shall be rounded to the nearest ton;

12.1.3. Periodic stack testing for ammonia emissions shall be submitted within 45 days of completion of the test.

If TransAlta elects to use continuous emission monitoring of ammonia instead of periodic stack testing, the quarterly report shall contain the 30 operating day rolling average ammonia concentration for both units averaged together for each operating day in the reporting period. Average ammonia concentrations shall be reported in units of ppmdv to 2 significant figures.

12.1.4 For each hour of boiler operation, the ammonia or urea injection rate in units of pounds of ammonia or urea/hour, , the boiler temperature at the point of injection, injection level in use, and the estimated ammonia emission concentration.

12.2. The emission monitoring report will be sent to SWCAA and Ecology electronically in a format acceptable to the SWCAA. Reporting to Ecology under this condition will end January 1, 2018.

13. Coal nitrogen and sulfur content information must be submitted to SWCAA and Ecology within 30 days of the end of each calendar quarter.

13.1. Coal nitrogen and sulfur reporting must include the date each coal sample is taken, the nitrogen and sulfur content of each coal sample analyzed, the average sulfur and nitrogen concentrations for the calendar quarter, and the maximum and minimum concentrations found during the calendar quarter.

13.2. After June 30, 2011, the report will include the rolling annual averages for nitrogen and sulfur content plus the maximum and minimum concentrations in the prior year.

13.2.1. The weekly coal sample test results will be retained for at least 5 years and available for review by Ecology or SWCAA upon request.

13.2.2. Coal quality reporting to Ecology will end the earlier of:

13.2.2.1. January 1, 2018, or
13.2.2.2. The decommissioning of either unit BW21 or BW22, or
13.2.2.3. The date monitoring of the quality of coal fired in units BW21 and BW22 is required by a regulation issued by EPA under the authority of Section 112 of the federal Clean Air Act.

Failure to comply with this Order may result in the issuance of civil penalties or other actions, whether administrative or judicial, to enforce the terms of this Order. Ecology shall enforce the terms of this Order only until such time as SWCAA incorporates the terms of the Order into the Centralia Power Plant's Air Operating Permit or except as provided by RCW 70.94.785.

You have a right to appeal this Order. To appeal you must:

- File your appeal with the Pollution Control Hearing Board within 30 days of the "date of receipt" of this document. Filing means actual receipt by the Board during regular office hours.
- Serve your appeal on the Department of Ecology within 30 days of the "date of receipt" of this document. Service may be accomplished by any of the procedures identified in WAC 371-08-305(10). "Date of receipt" is defined at RCW 43.21B.001(2).

If you appeal you must:

- Include a copy of this document with your Notice of Appeal.
- Serve and file your appeal in paper form; electronic copies are not accepted.

To file your appeal with the Pollution Control Hearing Board:

Mail appeal to:		Deliver your appeal in person to:
The Pollution Control Hearings Board PO Box 40903 Olympia, WA 98504-0903	OR	The Pollution Control Hearings Board 4224–6th Avenue SE Rowe Six, Bldg 2 Lacey, WA 98503

To serve your appeal on the Department of Ecology:

Mail appeal to:		Deliver your appeal in person to:
Department of Ecology Appeals Coordinator PO Box 47608 Olympia, WA 98504-7608	OR	Department of Ecology Appeals Coordinator 300 Desmond Drive SE Lacey, WA 98503

And send a copy of your appeal packet to:

Alan Newman
Department of Ecology
Air Quality Program
PO Box 47600
Olympia, WA 98504-7600

For additional information, go to the Environmental Hearings Office website at http://www.eho.wa.gov.

To find laws and agency rules, go to the Washington State Legislature website at http://www1.leg.wa.gov/CodeReviser.

Your appeal alone will not stay the effectiveness of this Order. Stay requests must be submitted in accordance with RCW 43.21B.320. These procedures are consistent with Chapter 43.21B RCW.

DATED this 13 day of Dec, 2011 at Olympia, Washington.

Jeff Johnston, Ph.D.
Manager, Science and Engineering Section
Department of Ecology
Air Quality Program

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-50:
2020 BART Order

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY

IN THE MATTER OF AN	]	
ADMINISTRATIVE ORDER AGAINST:	]	
	]	SECOND REVISION:
TransAlta Centralia Generation LLC	]	ORDER NO. 6426
	]	

TO: Mr. Mickey Dreher TransAlta Centralia Generation LLC
913 Big Hanaford Road
Centralia, WA 98531

This is an Administrative Order requiring your company to comply with WAC 173-400-151 by taking the actions that are described below. Chapter 70.94 RCW authorizes the Washington State Department of Ecology's Air Quality Program (Ecology) to issue Administrative Orders to require compliance with the requirements of Chapter 70.94 RCW and regulations issued to implement it.

Ecology has determined that portions of your facility are subject to the provisions of the state visibility protection program (WAC 173-400-151), which is implemented consistent with the requirements of the federal visibility protection program (40 CFR Part 51, Subpart P). The rules require that the State determine what technologies and level of emission control constitute Best Available Retrofit Technology (BART) for the eligible emission units at your facility. The rules also require the installation and use of those emission controls on the BART-eligible emission units. The emission controls are to be installed as expeditiously as possible, but in no event may the State allow them to start operation later than five years after the State's Regional Haze SIP amendment is approved by the United States Environmental Protection Agency (EPA).

FINDINGS

A. The TransAlta Centralia Generation LLC ("TransAlta") Centralia Power Plant is a coal fired power plant larger than 750 MW output subject to BART. The power plant is comprised of two identical coal fired units referred to as BW21 and BW22.

B. BART emission limitations for sulfur dioxide and particulate matter were determined by the Environmental Protection Agency in 2003. The Centralia Power Plant's Operating Permit incorporates the BART emission limitations determined by EPA.

C. BART for nitrogen oxides at the Centralia Power Plant is based on:

   a. Utilization of the selective non-catalytic reduction (SNCR) for nitrogen oxides control as appropriate.
   b. Low NO_x burners with separated and close coupled over fire air systems (aka LNC3).

c. Utilization of the Combustion Optimization System with Neural Network on BW22 as appropriate.
d. Use and installation of additional boiler heat recovery equipment and boiler tube cleaning equipment to maximize the extraction of fuel energy into boiler steam.

D. RCW 80.80.040 was amended in 2011 (Chapter 180, Laws of 2011) adding greenhouse gas emission requirements applicable to this facility that reduce the remaining useful life of each coal fired unit at the plant to approximately 8 and 13 years, starting from June 2011. The greenhouse gas emission requirements are:

a. Amendments to Chapter 80.80, Revised Code of Washington passed in 2011 require both coal fired units at the Centralia Power Plant to comply with the greenhouse gas emission performance standard requirements of Revised Code of Washington 80.80.040. One unit is required to comply by December 31, 2020. The other unit is required to comply by December 31, 2025.

b. The requirement to meet the greenhouse gas emission performance standard does not apply if the Department of Ecology determines that a state or federal requirement requires the installation of selective catalytic reduction (SCR) for nitrogen oxides control on the coal units.

Additional information and analysis is available in the BART Determination Support Document for the Centralia Power Plant, by the Washington State Department of Ecology, November 2008 (revised April 2010 and May 2011); and the BART Analysis for the Centralia Power Plant, June 2008 and the BART Analysis Supplement, December 2008, and supplemental information dated March 2010; and Chapter 180, Laws of 2011.

YOU ARE ORDERED: To install and operate in accordance with the following conditions:

BART Emission Limitations

1. Nitrogen Oxides emissions

1.1. Emissions of nitrogen oxides from the two coal-fired utility steam generating units (known as BW21 and BW22) at the Centralia Power Plant are limited, from the date of issuance of this Order, to:

1.1.1. 0.21 lb/MMBtu on the unit that does not have the Combustion Optimization System with Neural Network installed. This is a 30 operating day rolling average and includes all emissions during unit start-up and shut-down.

1.1.2. 0.18 lb/MMBtu on the unit that does have the Combustion Optimization System with Neural Network. This is a 30 operating day rolling average and includes all emissions during unit start-up and shut-down.

1.1.3. 0.18 lb/MMBtu on the unit that continues coal fired power generation starting January 1, 2021.

1.2. The 30 day rolling average will be determined per Condition 5.

1.3. TransAlta may use a variety of means as necessary to control emissions of nitrogen oxides to meet the prescribed NOx limit for BW21 and BW22 including the Combustion Optimization System with Neural Network, the SNCR, Low NOx Burners, boiler control, variety (source) of coal, or any combination thereof. Compliance with the nitrogen oxides emission limitation will be determined by use of a continuous emission monitoring system meeting the requirements of 40 CFR Part 75.

2. Ammonia emissions

2.1. Starting no later than the effective date of this order, emissions of ammonia from the two coal-fired utility steam generating units at the Centralia Power Plant are limited to a maximum of:

2.1.1. 10 parts per million, dry volume (ppmdv). This is a 30 operating day rolling average of both units averaged together.

2.1.2. In the event that during a given day, only one unit is operated, the average of both units will be the calendar day average of the operating boiler. The emission rate of zero for the unit that did not operate must not be included in calculating the average emissions.

2.2. The injection rate of urea (as the source of ammonia) to meet the nitrogen oxides emission in Section 1.1.1 and 1.1.2 is solely determined by TransAlta.

Schedule for Compliance

3. Coal units BW21 and BW22 will permanently cease coal-fired power generation operations as follows:

3.1. One of the units must cease no later than December 31, 2020.

3.2. The other unit must cease no later than December 31, 2025.

3.3. The unit that continues coal-fired power generation operations starting January 1, 2021, must comply with section 1.1.3.

3.4. Conditions 3.1 and 3.2 do not apply in the event the Department of Ecology determines as a requirement of state or federal law or regulation that the selective catalytic reduction technology must be installed on either coal fired unit.

[First amendment of the December 23, 2011, Memorandum of Agreement between the State of Washington and TransAlta Centralia Generation LLC, dated July 13, 2017.]

Monitoring and Recordkeeping Requirements

4. Ammonia

TransAlta is required to meet the nitrogen oxides emission limits of 1.1.1 and 1.1.2. Ammonia monitoring is only required when urea injection is used to meet those limits. The entirety of Section 4 applies in any calendar year (CY) in which urea injection is used by TransAlta to meet the emission limits of 1.1.1 or 1.1.2. TransAlta is not required to perform any of the monitoring and recordkeeping requirements in Section 4 if urea is not injected in the CY.

4.1. Ammonia emissions for compliance will be monitored by means of periodic emissions testing utilizing Bay Area Air Quality Management District (BAAQMD) Method ST1B or Environmental Protection Agency Conditional Test Method 027 (CTM-027). The sampling point will be in the stack following the wet scrubber. Stack testing shall occur on the following frequency:

4.1.1. Testing shall occur once each calendar year if the ammonia feed-rate exceeds 1.5 gpm during that calendar year. Testing will be performed while the SNCR is in operation and the feed-rate is above 1.5 gpm during testing, with no consecutive tests less than 80 or more than 110 calendar days apart.

4.1.2. If two consecutive tests are each more than the ammonia limitation (in 2.1.1), then the testing frequency decreases to once every six calendar months, provided the nitrogen oxides emission limit is complied with during the test.

4.1.3. If, after there are three consecutive tests less than the ammonia limitation, the next two consecutive tests are less than 50% of the ammonia emission limitation, then the testing frequency reduces to once annually, provided the nitrogen oxides emission limit is complied with during the tests.

4.1.4. The ammonia concentration measured during the periodic emissions testing is the 30 operating day rolling average value used for compliance starting on the date of the completion of the test until the completion of the next required periodic emission test.

5. Nitrogen oxides monitoring and averaging

5.1. For any hour in which coal is combusted in a unit, the owner/operator of that unit shall calculate the hourly nitrogen oxides concentration in lb/MMBtu at the CEMS installed in accordance with the requirements of 40 CFR Part 75. The 30-day average lb/MMBtu rate is calculated by summing the hourly emissions in pounds (unit lb/MMBtu multiplied by unit heat input) from that operating unit and dividing that by the sum of the hourly heat inputs in million Btu for that operating unit. At the end of that boiler's operating day, the owner/operator shall calculate and record a new 30-day rolling average emission rate in lb/MMBtu from all valid hourly data for that boiler's operating day and the previous 29 successive boiler operating days.

5.2. An hourly average nitrogen oxides emission rate is valid only if the minimum number of data points, as specified in 40 CFR Part 75, is acquired as necessary to calculate nitrogen oxides emissions and heat rate.

5.3. Data reported to meet the requirements of this section shall not include data substituted using the missing data substitution procedures of subpart D of 40 CFR part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR part 75.

5.4. A boiler operating day is a 24-hour period between 12 midnight and the following midnight during which coal is combusted at any time in the boiler. It is not necessary for coal to be combusted for the entire 24-hour period.

Reporting Requirements

6. A letter reporting achievement of each compliance date in the schedule in Condition 3 must be submitted to the Washington State Governor, Ecology, and SWCAA within 30 days of achieving the milestone.

7. A letter reporting TransAlta used urea injection must be sent to Ecology and SWCAA within 30 days of the first urea injection occurring during each calendar year. The letter must contain, at a minimum, the dates of urea injection, urea concentration, and the urea injection rate. No letter is required for any calendar year in which no urea injection occurred.

8. Emissions above the emission limitations in this order due to malfunctions must, at a minimum, be documented in writing and submitted to SWCAA and Ecology with 30 days after the end of each calendar quarter. Additional recordkeeping and notifications related to excess emissions may also be required by SWCAA or Ecology regulation. Excess emissions that TransAlta believes are unavoidable must be documented as required in WAC 173-400-107 (or section 109 after that section is approved into the Washington SIP) and SWCAA's unavoidable excess emissions requirements.

9. Emission monitoring data will be reported to Ecology and to the SWCAA.

9.1. Continuous emission monitoring reports will be submitted within 30 days after the end of each calendar quarter. The reports must contain the following information:

9.1.1. The 30 operating day rolling average pound nitrogen oxides/MMBtu for each operating day in the reporting period. The 30 day rolling average nitrogen oxides emission rate shall be reported as lb/MMBtu, with at least two significant figures;

9.1.2. The cumulative short tons of nitrogen oxides per unit and for both units combined that has been emitted during the current calendar year. The cumulative tons shall be rounded to the nearest ton;

9.1.3. The results of Section 4 testing for ammonia emissions, if they are required, shall be submitted within 45 days of completion of the test.

9.2. The emission monitoring report will be sent to SWCAA and Ecology electronically in a format acceptable to SWCAA.

Failure to comply with this Order may result in the issuance of civil penalties or other actions, whether administrative or judicial, to enforce the terms of this Order. Ecology shall enforce the terms of this Order only until such time as SWCAA incorporates the terms of the Order into the Centralia Power Plant's Air Operating Permit or except as provided by RCW 70.94.785.

You have a right to appeal this Order. To appeal you must:

- File your appeal with the Pollution Control Hearing Board within 30 days of the "date of receipt" of this document. Filing means actual receipt by the Board during regular office hours.
- Serve your appeal on the Department of Ecology within 30 days of the "date of receipt" of this document. Service may be accomplished by any of the procedures identified in WAC 371-08-305(10). "Date of receipt" is defined at RCW 43.21B.001(2).

If you appeal you must:

- Include a copy of this document with your Notice of Appeal.
- Serve and file your appeal in paper form; electronic copies are not accepted.

To file your appeal with the Pollution Control Hearing Board:

Mail appeal to:		Deliver your appeal in person to:
The Pollution Control Hearings Board PO Box 40903 Olympia, WA 98504-0903	OR	The Pollution Control Hearings Board 1111 Israel Rd. SW, STE 301 Tumwater, WA 98501

To serve your appeal on the Department of Ecology:

Mail appeal to:

Department of Ecology
Appeals Coordinator
PO Box 47608
Olympia, WA 98504-7608

OR

Deliver your appeal in person to:

Department of Ecology
Appeals Coordinator
300 Desmond Drive SE
Lacey, WA 98503

And send a copy of your appeal packet to:

Philip Gent
Department of Ecology
Air Quality Program
PO Box 47600
Olympia, WA 98504-7600

For additional information, go to the Environmental Hearings Office website at https://www.eluho.wa.gov.

To find laws and agency rules, go to the Washington State Legislature website at http://www.leg.wa.gov/CodeReviser.

Your appeal alone will not stay the effectiveness of this Order. Stay requests must be submitted in accordance with RCW 43.21B.320. These procedures are consistent with Chapter 43.21B RCW.

DATED this _29th__ day of _July_, 2020 at Olympia, Washington.

Martha Hankins

Martha Hankins
Manager, Policy and Planning Section
Department of Ecology
Air Quality Program

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-51:
2020 BART Order Technical Support

Technical Support Document for Second BART (Best Available Retrofit Technology) Order Revision

TransAlta Centralia Generation Plant

July 2020

Publication and Contact Information

For more information, contact:

Air Quality Program
P.O. Box 47600
Olympia, WA 98504-7600
360-407-6800

Washington State Department of Ecology — www.ecology.wa.gov

- Headquarters, Olympia 360-407-6000
- Northwest Regional Office, Bellevue 425-649-7000
- Southwest Regional Office, Olympia 360-407-6300
- Central Regional Office, Union Gap 509-575-2490
- Eastern Regional Office, Spokane 509-329-3400

ADA Accessibility

To request ADA accommodation, email phil.gent@ecy.wa.gov or call 360-407-6810, 711 (relay service), or 877-833-6341 (TTY).

Technical Support Document for Second BART (Best Available Retrofit Technology) Order Revision

TransAlta Centralia Generation Plant

Air Quality Program

Washington State Department of Ecology

Olympia, Washington

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Table of Contents

Executive Summary

TransAlta requested a revision to their existing BART order to mitigate fouling of their electrostatic precipitators (ESPs) with ammonia sulfate. In 2019, TransAlta experienced emission opacity readings that would have exceeded the opacity limits if TransAlta had not reduced plant capacity to compensate. The proposed mitigation is for TransAlta to install and operate a Combustion Optimization System with Neural Network (Neural Net) and have a lower nitrogen oxides (NOx) emission limit on the unit that is operational beyond 2020.

TransAlta was previously required to install Selective Non-Catalytic Reduction (SNCR) for control of nitrogen oxides emitted from their Centralia Power Plant. As a condition of the BART order issued to the facility, an optimization study was required to be performed and the results of that study implemented by the facility. After conducting the optimization study, TransAlta discovered that the ESPs were fouled from ammonia use required in the current BART order (Revision 1).

Southwest Clean Air Agency agreed to use enforcement discretion in 2019 on the urea injection rate while TransAlta was tuning the Neural Net. At the end of Calendar Year 2019, TransAlta had enough data to agree that the Neural Net system would be able to meet a 0.18 lb/MMBtu emission standard. TransAlta submitted a request to revise their BART order in January 2020.

TransAlta, Southwest Clean Air Agency, and Ecology agreed on the conditions for Revision 2 for the BART order to include lower nitrogen oxides limits, changes to the use and monitoring of ammonia, and removal of the requirement to analyze the coal sulfur and nitrogen content.

Reason for this Revision

Trans Alta requested a revision to their existing BART order to mitigate fouling of their electrostatic precipitators (ESPs) with ammonia sulfate. The proposed mitigation is for TransAlta to install in one boiler unit a Combustion Optimization System with Neural Network (Neural Net) in order to reduce the urea injection rate (the source of the ammonia). The other boiler unit is currently slated to cease coal-fired power generation on December 31, 2020 and is not scheduled to have the Neural Net installed. Ecology and Southwest Clean Air Agency are willing to accept a lower urea injection rate if TransAlta is willing to accept a lower nitrogen oxides emission limit. Ecology has determined that the nitrogen oxides reduction resulting from lowering the emission limit to 0.18 lb/MMBtu nitrogen oxides will be slightly beneficial for the environment and reduce regional haze.

Ecology will modify the BART order by:

- Lowering the nitrogen oxides emission limit on one unit to 0.18 lb/MMBTU
- Requiring the unit that continues to provide coal-fired power production after 2020 to meet the 0.18 lb/MMBtu nitrogen oxides.
- Changing the language to "Permanently cease coal-fired power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives" to match the new language in the MOA.
- Removing the requirement to sample the coal for nitrogen and sulfur content.
- Removing the requirement to report to Southwest Clean Air Agency results of coal test.
- Removing the requirement of a specific urea injection rate to allow TransAlta to inject urea as required (or if required) to meet the new emission standard.
- Changing the requirement for ammonia emission monitoring only to require monitoring when using a urea injection rate of greater than 1.5 gallons per minute

Ecology is also modifying the compliance schedule to eliminate the requirement to demolish the coal units to align the BART order's language with language in the Memorandum of Understanding (MOA) between the State of Washington and TransAlta.

SNCR and Other Related Changes

The requirement to install SNCR along with the requirement to meet Washington's greenhouse gas emission performance standard was enacted by the legislature in 2010. The legislative requirement resulted in the first BART order revision. This first revision was finalized in December 2011 and approved by EPA December 16, 2012.

Originally, Revision 2 was intended to incorporate the results of the SNCR Optimization Study required by Condition 5 of the First Revision of the amended 2012 BART order. The study was to demonstrate the proper use of ammonia in controlling emissions of nitrogen oxides generated by the combustion of coal in the TransAlta boilers. Goals of the study were to determine how low nitrogen oxides emissions could be attained while meeting an ammonia slip limit of 10 ppm.

TransAlta completed the required ammonia injection optimization testing in two phases. The first phase was completed and the required report submitted in September 2014. Ecology and Southwest Clean Air Agency requested additional testing. This additional testing was performed and updated test results were submitted in August 2016. The updated test results were accepted by Ecology and Southwest Clean Air Agency on November 7, 2016. Ecology's letter accepting the final report included a requirement for urea injection in Unit 1 at 1.2 gallons per minute and 2.0 gallons/minute in unit 2. The prescribed urea injection level was constant for all power generation levels.

Condition 5 of the First Revision of the BART order required TransAlta to submit a request to revise the BART order to reflect the results of the study. In a letter dated November 28, 2016, TransAlta requested specific revisions to the BART order to reflect the findings of the study.

Before Ecology was able to take action on TransAlta's request, TransAlta started a third optimization study in response to a compliance order with Southwest Clean Air Agency. The intent of the third optimization study was to fine-tune certain plant operating parameters and verify the result of the second optimization study. The results of the third study would augment or replace the results of the previous studies. An initial SNCR optimization test plan was submitted to Ecology by email on February 6, 2019.

In the summer of 2019, TransAlta experienced emission opacity readings that would have exceeded the opacity limits if TransAlta had not reduced plant capacity to compensate. During a maintenance shut-down of the facility, the electrostatic precipitators (ESPs) were examined. The ESPs had a visual fouling of all interior components, which dramatically reduced their efficiency. Samples of the material in the ESPs were analyzed and identified as ammonia sulfate. The source of ammonia in the system was from the reactions of urea in the SNCR system.

To decrease the ammonia slip in the SNCR, TransAlta installed a computerized emission control system called a Combustion Optimization System with Neural Network program (Neural Net). The Neural Net is able to monitor and adjust more system variables at the same time than the manual control system. TransAlta notified Ecology and Southwest Clean Air Agency by email on July 8, 2019 of the installation of the Neural Net and the start of tuning the system.

TransAlta submitted a request on January 30, 2020 to modify Revision 1 of the BART order. The modification proposes the installation of the Neural Net and eliminates the mandatory urea injection requirements.

Revision 2 incorporates those changes and removes outdated requirements.

Compliance schedule related change

On July 13, 2017, the Memorandum of Agreement (MOA) between the State of Washington and TransAlta was amended. Subsection D(5) of the Recitals was modified. The 2011 MOA stated, “permanently cease power generation…” The 2017 MOA amendment reads:

> (5) permanently cease coal-fired power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives, in each case pursuant to the terms and subject to the conditions of this MOA.

The change in the MOA does not require decommissioning of the units as envisioned (but not explicitly required) in 2011 with the passage of Chapter 180 (see Laws of 2011 - ESSB 5769 in 2011, codified in several locations). The change in the order reflects the pertinent portions of this law as codified in Chapters 80.80 and 80.82 RCW.

Ecology used the 2011 expectation that the plant would close to comply with the greenhouse gas emissions performance standard in RCW 80.08.040(3). Ecology also used the planned closure of the plant in the 2011 Regional Haze State Implementation Plan to project visibility benefits from the plant meeting the standard according to the schedule in the law. If power generation of the coal plant is replaced with a different form of combustion power generation (e.g., natural gas), the impact to regional haze would have to be analyzed separate from this BART order modification.

If TransAlta decides to switch to non-coal power generation, a Notice of Construction application would need to be submitted to Southwest Clean Air Agency by the company. Ecology would require the company to do, at a minimum, emissions modeling that would be required under the BART process to quantify the visibility impacts resulting from the operation as a natural gas boiler plant (EGU). This is similar to what we would require of a new power plant to determine if it meets the requirements of WAC 173-400-117, special protection requirements for federal Class I areas.

Basis for Decision

SNCR related changes and optimization study

As directed by BART order revision 1 and RCW 80.80.040, TransAlta installed an SNCR system to reduce nitrogen oxides emissions from the boilers. The installation was based on a design study by the system vendor, NALCO-NOx Mobotec.

NALCO/Mobotec took system measurements adequate to model the combustion process and optimize the locations of ammonia injection into the boilers. Modeling indicated that due to the configuration of the boilers, the lowest nitrogen oxides emission rate anticipated would be approximately 0.195 lb/MMBtu, assuming that modifications to optimize combustion in the fireboxes for Powder River Basin (PRB) sub-bituminous coal were completed.

Only Unit 2 (aka BW22) was modified for optimizing the combustion of PRB coals. These modifications, proposed in 2007, are known as the Flex Fuels Project. Unit 1 (aka BW21) is not modified and the company indicates that it is unlikely that the modifications will be installed on this unit.

The installed SNCR system includes three levels of injection lances in each boiler. The actual lances used depends on the firing rate. In general, to avoid making nitrogen oxides by oxidizing ammonia, the higher lances are used at high firing rates and the lower lances are used at low firing rates.

Ammonia is supplied by using urea. Urea is received as a 40 percent by weight urea solution. The urea is supplied to the lances via a variable speed pump that can supply up to 6 gallons per minute of the 40 percent urea solution to an eductor system. The water provides some cooling to the hot flue gas and carries the urea well beyond the lance ports allowing the nitrogen oxides reduction to occur over more volume of the boiler. At maximum injection rates, the system is capable of injecting ammonia at approximately the stoichiometric rate for the SNCR reaction at maximum heat input.

The modeling by NALCO/Mobotec on maximum reduction of nitrogen oxides has proven to be accurate in practice. Boiler/SNCR system modeling indicated that the maximum expected nitrogen oxides reduction would give an emission rate of 0.195 lb/MMBtu. Testing indicates that on Unit 2, the maximum reduction is to 0.19 lb/MMBtu and for Unit 1, 0.20 lb/MMBtu.

The initial reduction testing (reported in the September 2014 Optimization Study report) indicated that at low injection rates, the installed SNCR systems did not reduce nitrogen oxides beyond the levels being achieved by the use of the installed combustion controls. There was no significant nitrogen oxides reduction when the SNCR and combustion controls were both operated concurrently. The 2014 Optimization Study report indicated that the combination of SNCR and combustion control could achieve 0.21 lb nitrogen oxides/MMBtu. The current nitrogen oxides emission limit has been set to the achievable emission level of 0.21 lb nitrogen oxides/MMBtu.

Ecology and Southwest Clean Air Agency required TransAlta to complete additional urea injection studies to determine the effects of injection rates of up to 6 gpm of 40 percent urea solution on nitrogen oxides reduction. Two test series on each boiler were done at 2 boiler operating rates:

- A series of 15-minute tests at an operating rate of 686 MW, gross, and
- A series of 15-minute and 4 hours tests were done at an operating rate of 600 MW, gross.

Conclusions of TransAlta's optimization study

In conclusion, the 2014 and 2016 test results indicate that the injection rates developed by NALCO/Mobotec as their optimum injection rates are very close to what has been demonstrated in the most current study. TransAlta presented rationale for why the emission limits in the BART order should not be adjusted downward.

TransAlta's rationale included a conclusion that the effectiveness of the SNCR system is affected by numerous operational parameters. The plant operators have control over some, while others are out of their control. Operating parameters include market driven operating rates, fuel blend, physical condition of the boiler and auxiliary equipment, fuel staging at burners, air flow distribution, burner tilt, soot blowing intervals, tube fouling, water wall slagging, and temperature in the convective pass of the boiler. TransAlta argued that because the uncertainties listed above, the BART order should not be adjusted.

Ecology's evaluation of the optimization data

Test results indicate that a small reduction in average nitrogen oxides emissions may be achievable. The actual reduction depends on several operating parameters. Ecology has evaluated the possibility of reducing the 30-day average limitation from 0.21 to 0.20 lb/MMBtu. We note that if both units operated at full rate for every hour of the year (i.e., the potential to emit), a 0.01 lb/MMBtu reduction equates to about 590 tons per year out of a potential to emit rate of 12,900 tons.

TransAlta's current permits require the operation of the SNCR system with urea injection and emission limits of 0.21 lb/MMBtu. The urea injection rate is creating ammonia slip. The ammonia generation is reacting with sulfur to create ammonia sulfate that is plating the surfaces in the ESPs. This creates conditions where the facility has to run at a reduced rate to continuing meeting emission requirements.

Neural Net

TransAlta initial proposal was to substitute the Neural Net to reduce the urea injection rate for each unit. Ecology and Southwest Clean Air Agency were willing to accept a lower urea injection rate, but wanted TransAlta to meet the short-term emission values of 0.18 lb/MMBtu for the unit with the Neural Net installed on it. In July 2019, TransAlta did not know the effectiveness of the Neural Net system. TransAlta requested a delay in agreement until more testing was done.

Southwest Clean Air Agency agreed to use enforcement discretion in 2019 on the urea injection rate while TransAlta was tuning the Neural Net. At the end of Calendar Year 2019, TransAlta had enough data to agree that the Neural Net system would be able to meet a 0.18 lb/MMBtu emission standard. TransAlta submitted a request to revise their BART order in January 2020.

The main elements of the request are to:

- Install the Neural Net on Unit 2.
- Change the emission standard on Unit 2 to 0.18 lb/MMBtu from 0.21 lb/MMBtu.
- Allow TransAlta to use all methods and options they have available in any combination to meet the 0.18 lb/MMBtu standard.
- Change the ammonia monitoring requirements to reflect both historical readings and the change in urea injection rates.
- Remove the testing of coal for nitrogen and sulfur content as the facility would have to meet emission standards regardless of the coal used.
- Remove the reporting requirements for the coal nitrogen and sulfur content, as the test would no longer be performed.
- Change the permit language to reflect the new MOA language.

Compliance schedule related changes

The requirements of Chapter 80.80 RCW that sets the compliance schedule simply requires that to continue operation as a baseload power plant after the schedule in RCW 80.80.040(3)(c) and the BART order, each boiler must meet the greenhouse gas emission performance standard in effect on the day after the compliance dates. The standard is set by Washington Department of Commerce based on the emissions of combined cycle combustion turbines offered for sale and installed in the United States. This standard is currently 970 pounds of greenhouse gases/MWh. The standard is currently under review by Commerce for potential revision downward.

To continue operation after 2020 and 2025 with emissions above the greenhouse gas emission performance standard would require the plant owners to take an enforceable limit that keeps operations annually below a 60 percent capacity factor to avoid being classified as a baseload power plant under Chapter 80.80 RCW.

Ecology Analysis

The change in MOA language does not exclude the possibility that TransAlta could retrofit the facility to natural gas and continue operation. As the current BART order revision request does not address the future operation of the plant after 2025, any changes of this nature will require a separate action on the part of TransAlta. Until such time, it is assumed that TransAlta will cease all power generation activities by 2025.

Chapter 80.82 RCW was enacted in the same legislation that enacted special requirements for the Centralia Power Plant in Chapter 80.80 RCW. This law was drafted with the explicit understanding that the coal units would be decommissioned and demolished rather than repowered.

Ecology is aware that if TransAlta repowers the units on natural gas the visibility improvements anticipated by the current BART order and state implementation plan limits would not be met. Repowering would change the emission reduction used in determining the 2028 further progress goals for the nearby Class I Areas (Mt. Rainier and Olympic National Parks, and the Goat Rocks and Alpine Lakes Wilderness Areas) under the 2021 Regional Haze State Implementation Plan.

Proposed revision to emission limit in BART order

Ecology has determined that the small nitrogen oxides reduction resulting from lowering the emission limit to 0.18 lb/MMBtu nitrogen oxides will be slightly beneficial for the environment and reduce regional haze.

Ecology has determined that a change in ammonia monitor is applicable with the change from a mandatory urea injection rate to a rate dependent on meeting a specific nitrogen oxides emission standard. TransAlta historic ammonia emission sampling at their current urea injection rate has never indicated excessive ammonia emissions. A large part in this finding is that the SNCR is upstream in the emission pathway from the wet scrubber. Free ammonia in the exhaust stream would be absorbed by the slurry stream in the wet scrubber, as ammonia is hydrophilic. These two factors allow for modification of the ammonia monitoring.

Ecology will modify the BART order by:

- Lowering the nitrogen oxides emission standard on the second unit to 0.18 lb/MMBTU
- Requiring the unit that continues to provide coal-fired power production after 2020 to meet the 0.18 lb/MMBtu nitrogen oxides.

- Change the language to "permanently cease coal-fired power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives." This to match the new language in the MOA.
- Remove the requirement to sample the coal for nitrogen and sulfur content.
- Remove the requirement to report to Southwest Clean Air Agency results of coal test.
- Removing the requirement a specific urea injection rate to allow TransAlta to inject urea as required (or if required) to meet the new emission standard.
- Change the requirement for ammonia emission monitoring to reflect monitoring when using a urea injection rate of greater than 1.5 gallons per minute.

Proposed revision to compliance schedule in BART order

Ecology is proposing to modify the compliance schedule for coal units BW21 and BW22 to permanently cease coal-fired power generation operations by 2020 and 2025. This much more closely matches the requirement in the underlying state law.

Any request to repower one or both units at the Centralia plant would require that the impact of repowering on visibility be modeled. The modeling would have to meet both the requirements of BART modeling and satisfy the requirement of WAC 173-400-117. Since TransAlta has not requested repowering at this time, this issue will not be addressed in this BART order revision.

References

TransAlta's SNCR Optimization Study Report, September 20, 2014

TransAlta's SNCR Optimization Study Report, August 15, 2016

Ecology's SNCR Optimization Study Report acceptance letter dated November 7, 2016

Letter to Nancy Pritchett and Uri Papish, dated November 28, 2016

Southwest Clean Air Agency Regulatory Order #16-3202, issued December 13, 2016

TVW recording of March 15, 2011 House Environment Committee

Emission calculation

Appendix:

Response to Comment

From: Gent, Philip (ECY)
To: emissol@emissol.co
Subject: Response to submitted comment on TransAlta"s proposed BART Revision
Date: Monday, July 27, 2020 4:39:00 PM

To whom it may concern,

You submitted a comment in regards to a proposed revision to the TransAlta Centralia Generation LLC ("TransAlta") Centralia Power Plant's Best Available Retrofit Technology (BART) Order on 5/19/2020 at 1420. Below you will find your submitted comment and Ecology's response to your comment.

Submitted Comment

"Neural Network (NN) is a complex method and requires substantial testing, development and validation in order to make it work for any given environment. We trust the applicant has gone thru its due process for this development and demonstration. It is imperative that sufficient evidence is provided, showing a certain NN algorithm has been developed and specifically shown to work for the said environment in the powerplant."

Response to comment

Thank you for your comment. TransAlta along with Neuendorfer and Griffin Open Systems installed a temporary neural network interfacing with the plant distributed control system starting July 8, 2019. The system had no control elements and was only learning and modeling the systems. Griffin engineers built a model to perform predictive modeling and started to collect tuning data.

The neural network interface continued to collect tuning data and in October, 2019, TransAlta Corporate approved and issued an authorization for expenditure for the entire neural network installation. The installation plan was to have the neural network operational the first week of November. The actual transition time took longer than planned and the commission date was extended to December 19, 2019.

The months of installation and modification of the neural network in order to reduce and optimize NOx emissions gave TransAlta the confidence to request a change to their existing BART Order. From the time of control system commissioning (December 19, 2019 being the day Griffin and Neuendorfer left the site) until the unit came offline for the spring outage on February 11, 2020, average NOX emissions have been below 0.18 lb/MMBtu. As the request to lower the NOx emission limit came from the Permittee (TransAlta), it is incumbent on TransAlta to meet the limits.

No change was made to the BART Order as a result of this comment.

Philip Gent, PE
Senior Engineer
Policy & Planning Section
Washington Department of Ecology
(360) 407-6810
Philip.Gent@ecy.wa.gov

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-52:
Centralia Hazardous Substances Releases: Preliminary Determination (Sept. 2025)

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
Southwest Region Office
PO Box 47775 • Olympia, WA 98504-7775 • 360-407-6300

September 4, 2025

Mickey Dreher
TransAlta Centralia Generation LLC
913 Big Hanaford Rd,
Centralia, WA 98531-9101

Re: Preliminary Determination of Liability for Release of Hazardous Substances at the following Contaminated Site:

- **Site Name:** Centralia Steam Plant
- **Site Address:** 913 Big Hanaford Rd, Centralia, WA 98531-9101
- **Cleanup Site ID:** 17302
- **Facility/Site ID:** 94772166

Dear Mickey Dreher:

Based on credible evidence, the Department of Ecology (Ecology) is proposing to find TransAlta Centralia Generation LLC liable under the Model Toxics Control Act (MTCA), Chapter 70A.305 RCW, for the release of hazardous substances at the Centralia Steam Plant (Site). Any person whom Ecology finds, based on credible evidence, to be liable is known under MTCA as a "potentially liable person" or "PLP."

This letter identifies the basis for Ecology's proposed finding and your opportunity to respond to that finding. This letter also describes the scope of your potential liability and next steps in the cleanup process at the Site.

Proposed Finding of Liability

Ecology is proposing to find TransAlta Centralia Generation LLC liable under RCW 70A.305.040 for the release of hazardous substances at the Site. This proposed finding is based on the following evidence:

1. TransAlta Centralia Generation LLC is the current owner and operator of the TransAlta Steam Plant (Site) located at 913 Big Hanaford Rd, Centralia Washington 98531 including Lewis County Parcels **23340001000,23340002002,23340003000,23340004000,23340005001,233400**

05002,
23340005003,23340005004,23436000000,23345000000,23355001006,23355001007,
23355001008,23355002002.

2. The property is and has been historically operated as a coal-fired electric plant with associated energy production activities.

3. The owner has provided a draft remedial investigation (TRC Environmental Corporation, Remedial Investigation Report, TransAlta Centralia Generation LLC, 913 Big Hanaford Road, Centralia WA, May 13, 2025) that identifies releases including metals, volatile organic compounds, semi-volatile organic compounds (SVOCs), and total petroleum hydrocarbons, to soil, groundwater, and sediment above MTCA cleanup levels. The facility's operation as a coal burning power generation plant likely released particulate containing dioxins and furans, SVOCs, and select metals including mercury from its smokestacks into the environment surrounding the facility.

Opportunity to Respond to Proposed Finding of Liability

In response to Ecology's proposed finding of liability, you may either:

1. Accept your status as a PLP without admitting liability and expedite the process through a voluntary waiver of your right to comment. This may be accomplished by signing and returning the enclosed form or by sending a letter containing similar information to Ecology; or

2. Challenge your status as a PLP by submitting written comments to Ecology within thirty (30) calendar days of the date you receive this letter; or

3. Choose not to comment on your status as a PLP.

Please submit your waiver or written comments to the following address:

Thomas Middleton
Southwest Regional Office
Toxics Cleanup Program
PO Box 47775
Olympia, WA 98504-7775

After reviewing any comments submitted, or after 30 days if no response has been received, Ecology will make a final determination regarding your status as a PLP and provide you with written notice of that determination.

Identification of Other Potentially Liable Persons

If you are aware of any other persons who may be liable for the release of hazardous substances at the Site, Ecology encourages you to provide us with their identities and the reason you believe they are liable. Ecology also suggests you contact these other persons to discuss how you can jointly work together to most efficiently clean up the Site.

Responsibility and Scope of Potential Liability

Ecology may either conduct or require PLPs to conduct remedial actions to investigate and clean up the release of hazardous substances at a site. PLPs are encouraged to initiate discussions and negotiations with Ecology and the Office of the Attorney General that may lead to an agreement on the remedial action to be conducted.

Each liable person is strictly liable, jointly and severally, for all remedial action costs and for all natural resource damages resulting from the release of hazardous substances at a site. If Ecology incurs remedial action costs in connection with the investigation or cleanup of real property and those costs are not reimbursed, then Ecology has the authority under RCW 70A.305.060 to file a lien against that real property to recover those costs.

Next Steps in Cleanup Process

In response to the release of hazardous substances at the Site, Ecology intends to conduct the following actions under MTCA:

1. Ecology has completed the Initial Investigation/Site Hazard Assessment (II/SHA) and prepared an Early Notice Letter (ENL). Ecology will engage with TransAlta Generation Centralia LLC to develop an Agreed Order at the Site.

2. Ecology will continue to work with TransAlta Generation Centralia LLC to complete its closure requirements and obligations under RCW Chapter 80.82 and the Memorandum of Agreement between TransAlta and the State of Washington dated December 23, 2011.

For a description of the process for cleaning up a contaminated site under MTCA, please refer to the enclosed fact sheet.

Ecology's policy is to work cooperatively with PLPs to accomplish the prompt and effective cleanup of contaminated sites. Please note that your cooperation in planning or conducting remedial actions at the Site is not an admission of guilt or liability.

Contact Information

If you have any questions regarding this letter or if you would like additional information regarding the cleanup of contaminated sites, please contact me at 360-999-9594 or thomas.middleton@ecy.wa.gov. Thank you for your cooperation.

Sincerely,

Thomas Middleton
Cleanup Project Manager
Toxics Cleanup Program, SWRO

Enclosures (2)

1. FOCUS: MODEL TOXICS CONTROL ACT CLEANUP REGULATION: PROCESS FOR CLEANUP OF HAZARDOUS WASTE SITES (#94-129)
2. PLP WAIVER FORM TEMPLATE

By certified mail: 9489 0090 0027 6341 0492 85

cc: Conrad Wieclaw, Vincent Light, (Transalta): Conrad_Wieclaw@transalta.com
Dan Lawler,Office of the Attorney General:dan.lawler@atg.wa.gov
Ivy Anderson, Office of the Attorney General: Ivy.Anderson@atg.wa.gov
Marian Abbett, SWRO TCP Section Manager: marian.abbett@ecy.wa.gov
Bobbak Talebi, SWRO Regional Director: bobbak.talebi@ecy.wa.gov
Ecology Site File

WASHINGTON STATE DEPARTMENT OF ECOLOGY

Focus

Model Toxics Control Act Cleanup Regulation: Process for Cleanup of Hazardous Waste Sites

In March of 1989, an innovative, citizen-mandated toxic waste cleanup law went into effect in Washington, changing the way hazardous waste sites in this state are cleaned up. Passed by voters as Initiative 97, this law is known as the Model Toxics Control Act, chapter 70.105D RCW. This fact sheet provides a brief overview of the process for the cleanup of contaminated sites under the rules Ecology adopted to implement that Act (chapter 173-340 WAC).

How the Law Works

The cleanup of hazardous waste sites is complex and expensive. In an effort to avoid the confusion and delays associated with the federal Superfund program, the Model Toxics Control Act is designed to be as streamlined as possible. It sets strict cleanup standards to ensure that the quality of cleanup and protection of human health and the environment are not compromised. At the same time, the rules that guide cleanup under the Act have built-in flexibility to allow cleanups to be addressed on a site-specific basis.

The Model Toxics Control Act funds hazardous waste cleanup through a tax on the wholesale value of hazardous substances. The tax is imposed on the first in-state possessor of hazardous substances at the rate of 0.7 percent, or $7 per $1,000. Since its passage in 1988, the Act has guided the cleanup of thousands of hazardous waste sites that dot the Washington landscape. The Washington State Department of Ecology's Toxic Cleanup Program ensures that these sites are investigated and cleaned up.

What Constitutes a Hazardous Waste Site?

Any owner or operator who has information that a hazardous substance has been released to the environment at the owner or operator's facility and may be a threat to human health or the environment must report this information to the Department of Ecology (Ecology). If an "initial investigation" by Ecology confirms further action (such as testing or cleanup) may be necessary, the facility is entered onto either Ecology's "Integrated Site Information System" database or "Leaking Underground Storage Tank" database. These are computerized databases used to track progress on all confirmed or suspected contaminated sites in Washington State. All confirmed sites that have not been already voluntarily cleaned up are ranked and placed on the state "Hazardous Sites List." Owners, operators, and other persons known to be potentially liable for the cleanup of the site will receive an "Early Notice Letter" from Ecology notifying them that their site is suspected of needing cleanup, and that it is Ecology's policy to work cooperatively with them to accomplish prompt and effective cleanup.

Who is Responsible for Cleanup?

Any past or present relationship with a contaminated site may result in liability. Under the Model Toxics Control Act a potentially liable person can be:

- A current or past facility owner or operator.
- Anyone who arranged for disposal or treatment of hazardous substances at the site.
- Anyone who transported hazardous substances for disposal or treatment at a contaminated site, unless the facility could legally receive the hazardous materials at the time of transport.
- Anyone who sells a hazardous substance with written instructions for its use, and abiding by the instructions results in contamination.

In situations where there is more than one potentially liable person, each person is jointly and severally liable for cleanup at the site. That means each person can be held liable for the entire cost of cleanup. In cases where there is more than one potentially liable person at a site, Ecology encourages these persons to get together to negotiate how the cost of cleanup will be shared among all potentially liable persons.

Ecology must notify anyone it knows may be a "potentially liable person" and allow an opportunity for comment before making any further determination on that person's liability. The comment period may be waived at the potentially liable person's request or if Ecology has to conduct emergency cleanup at the site.

Achieving Cleanups through Cooperation

Although Ecology has the legal authority to order a liable party to clean up, the department prefers to achieve cleanups cooperatively. Ecology believes that a non-adversarial relationship with potentially liable persons improves the prospect for prompt and efficient cleanup. The rules implementing the Model Toxics Control Act, which were developed by Ecology in consultation with the Science Advisory Board (created by the Act), and representatives from citizen, environmental and business groups, and government agencies, are designed to:

- Encourage independent cleanups initiated by potentially liable persons, thus providing for quicker cleanups with less legal complexity.
- Encourage an open process for the public, local government and liable parties to discuss cleanup options and community concerns.
- Facilitate cooperative cleanup agreements rather than Ecology-initiated orders. *Ecology can, and does, however use enforcement tools in emergencies or with recalcitrant potentially liable persons.*

What is the Potentially Liable Person's Role in Cleanup?

The Model Toxics Control Act requires potentially liable persons to assume responsibility for cleaning up contaminated sites. For this reason, Ecology does not usually conduct the actual cleanup when a potentially liable person can be identified. Rather, Ecology oversees the cleanup of sites to ensure that investigations, public involvement and actual cleanup and monitoring are done appropriately. Ecology's costs of this oversight are required to be paid by the liable party.

When contamination is confirmed at the site, the owner or operator may decide to proceed with cleanup without Ecology assistance or approval. Such "independent cleanups" are allowed under the Model Toxics Control Act under most circumstances, but must be reported to Ecology, and are done at the owner's or operator's own risk. Ecology may require additional cleanup work at these sites to bring them into compliance with the state cleanup standards. Most cleanups in Washington are done independently.

Other than local governments, potentially liable persons conducting independent cleanups do not have access to financial assistance from Ecology. Those who plan to seek contributions from other persons to help pay for cleanup costs need to be sure their cleanup is "the substantial equivalent of a department-conducted or department-supervised remedial action." Ecology has provided guidance on how to meet this requirement in WAC 173-340-545. Persons interested in pursuing a private contribution action on an independent cleanup should carefully review this guidance prior to conducting site work.

Working with Ecology to Achieve Cleanup

Ecology and potentially liable persons often work cooperatively to reach cleanup solutions. Options for working with Ecology include formal agreements such as consent decrees and agreed orders, and seeking technical assistance through the Voluntary Cleanup Program. These mechanisms allow Ecology to take an active role in cleanup, providing help to potentially liable persons and minimizing costs by ensuring the job meets state standards the first time. This also minimizes the possibility that additional cleanup will be required in the future – providing significant assurances to investors and lenders.

Here is a summary of the most common mechanisms used by Ecology:

- **Voluntary Cleanup Program**: Many property owners choose to cleanup their sites independent of Ecology oversight. This allows many smaller or less complex sites to be cleaned up quickly without having to go through a formal process. A disadvantage to property owners is that Ecology does not approve the cleanup. This can present a problem to property owners who need state approval of the cleanup to satisfy a buyer or lender.

  One option to the property owner wanting to conduct an independent cleanup yet still receive some feedback from Ecology is to request a technical consultation through Ecology's Voluntary Cleanup Program. Under this voluntary program, the property owner submits a cleanup report with a fee to cover Ecology's review costs. Based on the review, Ecology either issues a letter stating that the site needs "No Further Action" or identifies what additional work is needed. Since Ecology is not directly involved in the site cleanup work, the level of certainty in Ecology's response is less than in a consent decree or agreed order. However, many persons have found a "No Further Action" letter to be sufficient for their needs, making the Voluntary Cleanup Program a popular option.

- **Consent Decrees:** A consent decree is a formal legal agreement filed in court. The work requirements in the decree and the terms under which it must be done are negotiated and agreed to by the potentially liable person, Ecology and the state Attorney General's office. Before consent decrees can become final, they must undergo a public review and comment period that typically includes a public hearing. Consent decrees protect the potentially liable person from being sued for "contribution" by other persons that incur cleanup expenses at the site while facilitating any contribution claims against the other persons when they are responsible for part of the cleanup costs. Sites cleaned up under a consent decree are also exempt from having to obtain certain state and local permits that could delay the cleanup.

- ***De Minimus* Consent Decree:** Landowners whose contribution to site contamination is "insignificant in amount and toxicity" may be eligible for a de minimus consent decree. In these decrees, landowner typically settle their liability by paying for some of the cleanup instead of actually conducting the cleanup work. Ecology usually accepts a de minimus settlement proposal only if the landowner is affiliated with a larger site cleanup that Ecology is currently working on.
- **Prospective Purchaser Consent Decree:** A consent decree may also be available for a "prospective purchaser" of contaminated property. In this situation, a person who is not already liable for cleanup and wishes to purchase a cleanup site for redevelopment or reuse may apply to negotiate a prospective purchaser consent decree. The applicant must show, among other things, that they will contribute substantial new resources towards the cleanup. Cleanups that also have a substantial public benefit will receive a higher priority for prospective purchaser agreements. If the application is accepted, the requirements for cleanup are negotiated and specified in a consent decree so that the purchaser can better estimate the cost of cleanup before buying the land.
- **Agreed Orders:** Unlike a consent decree, an agreed order is not filed in court and is not a settlement. Rather, it is a legally binding administrative order issued by Ecology and agreed to by the potentially liable person. Agreed orders are available for remedial investigations, feasibility studies, and final cleanups. An agreed order describes the site activities that must occur for Ecology to agree not to take enforcement action for that phase of work. As with consent decrees, agreed orders are subject to public review and offer the advantage of facilitating contribution claims against other persons and exempting cleanup work from obtaining certain state and local permits.

Ecology-Initiated Cleanup Orders

Administrative orders requiring cleanup activities without an agreement with a potentially liable person are known as **enforcement orders**. These orders are usually issued to a potentially liable person when Ecology believes a cleanup solution cannot be achieved expeditiously through negotiation or if an emergency exists. If the responsible party fails to comply with an enforcement order, Ecology can clean up the site and later recover costs from the responsible person(s) at up to three times the amount spent. The state Attorney General's Office may also seek a fine of up to $25,000 a day for violating an order. Enforcement orders are subject to public notification.

Financial Assistance

Each year, Ecology provides millions of dollars in grants to local governments to help pay for the cost of site cleanup. In general, such grants are available only for sites where the cleanup work is being done under an order or decree. Ecology can also provide grants to local governments to help defray the cost of replacing a public water supply well contaminated by a hazardous waste site. Grants are also available for local citizen groups and neighborhoods affected by contaminated sites to facilitate public review of the cleanup. See Chapter 173-322 WAC for additional information on grants to local governments and Chapter 173-321 WAC for additional information on public participation grants.

Public Involvement

Public notices are required on all agreed orders, consent decrees, and enforcement orders. Public notification is also required for all Ecology-conducted remedial actions.

Ecology's Site Register is a widely used means of providing information about cleanup efforts to the public and is one way of assisting community involvement. The Site Register is published every two weeks to inform citizens of public meetings and comment periods, discussions or negotiations of legal agreements, and other cleanup activities. The Site Register can be accessed on the Internet at: www.ecy.wa.gov/programs/tcp/pub_inv/pub_inv2.html.

How Sites are Cleaned Up

The rules describing the cleanup process at a hazardous waste site are in chapter 173-340 WAC. The following is a general description of the steps taken during the cleanup of an average hazardous waste site. Consult the rules for the specific requirements for each step in the cleanup process.

1. Site Discovery: Sites where contamination is found must be reported to Ecology's Toxics Cleanup Program within 90 days of discovery, unless it involves a release of hazardous materials from an underground storage tank system. In that case, the site discovery must be reported to Ecology within 24 hours. At this point, potentially liable persons may choose to conduct independent cleanup without assistance from the department, but cleanup results must be reported to Ecology.

2. Initial Investigation: Ecology is required to conduct an initial investigation of the site within 90 days of receiving a site discovery report. Based on information obtained about the site, a decision must be made within 30 days to determine if the site requires additional investigation, emergency cleanup, or no further action. If further action is required under the Model Toxics Control Act, Ecology sends early notice letters to owners, operators and other potentially liable persons inviting them to work cooperatively with the department.

3. Site Hazard Assessment: A site hazard assessment is conducted to confirm the presence of hazardous substances and to determine the relative risk the site poses to human health and the environment.

4. Hazard Ranking: The Model Toxics Control Act requires that sites be ranked according to the relative health and environmental risk each site poses. Working with the Science Advisory Board, Ecology created the Washington Ranking Method to categorize sites using data from site hazard assessments. Sites are ranked on a scale of 1 to 5. A score of 1 represents the highest level of risk and 5 the lowest. Ranked sites are placed on the state Hazardous Sites List.

5. Remedial Investigation/Feasibility Study: A remedial investigation and feasibility study is conducted to define the extent and magnitude of contamination at the site. Potential impacts on human health and the environment and alternative cleanup technologies are also evaluated in this study. Sites being cleaned up by Ecology or by potentially liable persons under a consent decree, agreed order or enforcement order are required to provide for a 30 day public review before finalizing the report.

6. Selection of Cleanup Action: Using information gathered during the study, a cleanup action plan is developed. The plan identifies preferred cleanup methods and specifies cleanup standards and other requirements at the site. A draft of the plan is subject to public review and comment before it is finalized.

7. Site Cleanup: Actual cleanup begins when the cleanup action plan is implemented. This includes design, construction, operation and monitoring of cleanup actions. A site may be taken off the Hazardous Sites List after cleanup is completed and Ecology determines cleanup standards have been met.

PLP Waiver Form Template

[PLP SIGNATORY]
[PLP COMPANY]
[STREET ADDRESS]
[CITY, STATE] [POSTAL CODE]

Pursuant to WAC 173-340-500 and WAC 173-340-520(1)(b)(i), I [NAME], a duly authorized representative of [COMPANY NAME], do hereby waive the right to the thirty (30) day notice and comment period described in WAC 173-340-500(3) and accept status of [COMPANY NAME] as a Potentially Liable Person at the following contaminated site:

- Site Name: [CLEANUP SITE NAME]
- Site Address: [CLEANUP SITE ADDRESS]
- Cleanup Site ID: [CLEANUP SITE NUMBER]
- Facility/Site ID: [FACILITY/SITE NUMBER]
- [OPTIONAL: County Assessor's Parcel Number(s): [NUMBERS]]

By waiving this right, [COMPANY NAME] makes no admission of liability.

______________________________ ______________________________

Signature Date

Relation to the Site: [for example, owner or operator]

For More Information / Special Accommodation Needs

If you would like more information about the state Model Toxics Control Act, please call us toll-free at **1-800-826-7716**, or contact your regional Washington State Department of Ecology office listed below. Information about site cleanup, including a listing of ranked hazardous waste sites, is also accessible through our Internet address: http://www.ecy.wa.gov/programs/tcp/cleanup.html

- **Northwest Regional Office** **425/649-7000**
  (Island, King, Kitsap, San Juan, Skagit, Snohomish, Whatcom Counties)
- **Southwest Regional Office** **360/407-6300**
  (Southwestern Washington, Olympic Peninsula, Pierce, Thurston and Mason Counties)
- **Central Regional Office** **509/575-2490**
  (Benton, Chelan, Douglas, Kittitas, Klickitat, Okanogan, Yakima Counties)
- **Eastern Regional Office** **509/329-3400**
  (Adams, Asotin, Columbia, Ferry, Franklin, Garfield, Grant, Lincoln, Pend Oreille, Spokane, Stevens, Walla Walla, Whitman Counties)

If you need this publication in an alternative format, please contact the Toxics Cleanup Program at (360) 407-7170. Persons with a hearing loss can call 711 for the Washington Relay Service. Persons with a speech disability can call 877-833-6341.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-53:
Centralia Pollution Inspection (June 2025)

DEPARTMENT OF ECOLOGY
State of Washington

☐ Check this box if you have attached any documents to this form (using the paperclip icon on the left).

ERTS #(s):	None
Parcel # (s):	See additional info box
County:	Lewis
FSID #:	94772166
CSID #:	17302
UST #:	8710

SITE INFORMATION

Site Name (Name over door): **TransAlta Centralia**	Site Address (including City, State, and Zip): 913 Big Hanaford Rd, Centralia, WA 98531	Phone Click to enter text. Email Click to enter text.
Site Contact, Title, Business: **Conrad Wieclaw**	Site Contact Address (including City, State, and Zip): **913 Big Hanaford Rd, Centralia, WA 98531**	Phone **360-807-8093** Email **Conrad_Wieclaw@transalta.com** Click to enter text.
Site Owner, Title Business: **TransAlta Centralia Generation LLC**	Site Owner Address (including City, State, and Zip): **913 Big Hanaford Rd, Centralia, WA 98531**	Phone **360-736-9901** Email **Centralia@transalta.com**
Site Owner Contact, Title, Business: **Trans Alta Corporation**	Site Owner Contact Address (Including City, State, and Zip **TransAlta Place, Suite 1400, 1100 1 St SE, Calgary, Alberta Canada T2G 1B1**	Phone **403-267-7110** Email Click to enter text.
Previous Site Owner(s):	Additional Info (for any Site Information Item): **23340001000,23340002002,23340003000,23340004000,23340005001,23340005002, 23340005003,23340005004,23436000000,23345000000,23355001006,23355001007, 23355001008,23355002002.**	
Alternate Site Name(s): Click to enter text.		

Latitude (Decimal Degrees):	**46.75487**
Longitude (Decimal Degrees):	**-122.8636**

INSPECTION INFORMATION

☒ Please check this box if there is relevant inspection information, such as data or photos, in an existing site report for this site.

Inspection Conducted? Yes ☐ No ☒	Date/Time: Click to enter text.	Entry Notice:	Announced ☐	Unannounced ☐
Photographs taken?	Yes ☐	No ☒	Note: Attach photographs or upload to PIMS	
Samples Collected?	Yes ☐	No ☒	Note: Attach record with media, location, depth, etc.	

RECOMMENDATION

No Further Action (Check appropriate box below):		**LIST on Contaminated Sites List:** ☒
Release or threatened release does not pose a threat	☐	
No release or threatened release	☐	**LIST on NFA Sites List:** ☐
Refer to program/agency (Name: Click to enter text.)	☐	
Independent Cleanup Action Completed (contamination removed)	☐	

COMPLAINT (Brief Summary of ERTS Complaint):

Property representatives reported contamination above MTCA cleanup standards during Site investigations

CURRENT SITE STATUS (Brief Summary of why Site is recommended for Listing or NFA):

I recommend this Site for a listing on the Contaminated Sites List. The submitted report indicates contamination above MTCA cleanup standards.

Investigator: **Thomas Middleton, L.HG**	Date Submitted: 6/2/2025

OBSERVATIONS ☐ **Please check this box if you included information on the Supplemental Page at end of report.**

Description (If site visit made, please be sure to include the following: site observations, site features and cover, chronology of events, sources/past practices likely responsible for contamination, presence of water supply wells and other potential exposure pathways, etc):

There are six COCs for soil at the Site. These COCs are further divided into nine Remedial Areas (RAs) for discussion of vertical and horizontal distribution of COCs in soil. The RAs are summarized below:

- **Arsenic:** Remedial Areas 1, 2, and 8. The distribution of arsenic impacts is displayed on Figures 12 and 13.
- **Barium:** Remedial Areas 1, 5, 6, 8, and 9. The distribution of barium impacts is displayed on Figures 14 and 15.
- **Cadmium:** Remedial Areas 3, 5, 6, and 8. The distribution of cadmium impacts is displayed on Figures 16 and 17.
- **Copper:** Remedial Areas 1, 4, and 7. The distribution of copper impacts is displayed on Figures 18 and 19.
- **Selenium**: Remedial Area 8. The distribution of selenium impacts is displayed on Figure 20.
- **Zinc**: Remedial Area 2. The distribution of zinc impacts is displayed on Figure 21.

As identified above, there are nine Remedial Areas (RAs) with COCs at concentrations exceeding CULs.

There are nine COCs for groundwater at the Site. These COCs are summarized below and are based on groundwater samples collected from February 2023 to December 2024:

- **Arsenic (dissolved and total):** The distribution of arsenic impacts is displayed on Figures 23 through 27 in both the shallow and deep aquifers. The area of impacts in the shallow aquifer is predominantly near the Surge Pond, North Effluent Pond, and South Effluent Pond, with isolated pockets near the bottom ash pile and north of the North Coal Pile Runoff Ditch.

  The highest arsenic concentration in the deeper aquifer was from the off-property monitoring well CMWD-2 in both May and December 2024. Groundwater flow in the deeper aquifer is consistently toward the southeast. Based on the redox potential analysis of groundwater at the Site, these higher concentrations may be the result of anoxic groundwater conditions. Anoxic groundwater conditions significantly influence the mobility and concentration of naturally occurring arsenic and manganese at depth, especially where organic matter or other reducing agents are present.

- **Chromium (total):** The distribution of chromium impacts is displayed on Figures 28 through 30 in the shallow aquifer. No samples exceeded the chromium CUL from the deeper aquifer. Chromium impacts in the shallow aquifer exceeded CULs in monitoring wells CMW-16 (February 2023 and May 2024), CMW-32 (February 2023), and CMW-43 (December 2024). Corresponding chromium impacts to soil were not observed at levels exceeding CULs in these areas.

- **Copper (total):** While copper was retained as a COC for groundwater, only one sample exceeded the CUL in the shallow aquifer. Monitoring well CMW-16 exceeded the CUL in May 2024 at a concentration of 19 µg/L. The CUL for protection of surface water aquatic life is 11 µg/L. No samples exceeded the respective CUL from the deeper aquifer.

- **Manganese (dissolved and total):** The distribution of manganese impacts is displayed on Figures 31 through 35 in both the shallow and deep aquifers. Impacts to the shallow and deep aquifers were not fully delineated in May and December 2024 but the highest concentrations were observed upgradient of the facility, north of the CPRO Ponds and north of Hanaford Creek. This is most likely due to the naturally occurring metals at depth and the anoxic and hydric soil conditions to the north of the facility. As described in the 2019 Environmental Science & Technology, *Elevated Manganese Concentrations in United States Groundwater, Role of Land Surface- Soil- Aquifer Connections* (McMahon et al. 2018), the concentration of manganese is significantly higher in wells where hydric soils are present within a 500-meter buffer around the well.

- **Selenium (dissolved and total):** The distribution of selenium impacts is displayed on Figures 36 through 38 in the shallow aquifer. Selenium impacts exceeding the CUL of 5 µg/L were observed in the area surrounding the coal pile and the CPRO Ponds in February 2023 and December 2024. In May 2024, the selenium exceedances in the shallow aquifer were restricted to only monitoring well CMW-43, near Cooling Tower 1B.

  Selenium was not detected at a concentration exceeding the CUL of 80 µg/L in the deeper aquifer. The highest concentration in the deeper aquifer was 1.9 µg/L in December 2024 from monitoring well CMWD-1.

- **Zinc (dissolved and total):** The distribution of zinc impacts is displayed on Figures 39 through 41 in the shallow aquifer.

- **1-Methylnaphthalene:** 1-methlnaphthalene was detected in one monitoring well, CMW-16, exceeding the CUL of 0.86 µg/L. No other samples exceeded the MDL in both the shallow and deep aquifers.

- **TPH – Diesel-Range Organics:** The distribution of TPH-DRO impacts is displayed on Figures 42 through 44 in the shallow aquifer. Samples collected from monitoring well CMW-16, exceeded the CUL of 500 µg/L during all three sampling events. Based on the silica gel cleanup results collected in December 2024, there are other sources of polar organic compounds contributing to the weathered petroleum mixture, most likely from naturally occurring organic matter. Use of silica gel cleanup is recommended going forward to distinguish the non-petroleum polar organics in the samples. No TPH-DRO was detected exceeding the MDL in the deeper aquifer.

Vinyl Chloride: Vinyl chloride was only detected in two monitoring wells at a concentration exceeding the CUL of 0.02 µg/L for protection of surface water: temporary monitoring well CTMW-2 located south of the South Effluent Pond, and monitoring well CMW-27. The exceedance in temporary well CTMW-2 in February 2023 has not been encountered in surrounding groundwater monitoring wells CMW-6, CMW-8, and CMW-17.

There are six COCs for sediment at the Site. The spatial distribution of these COCs exceeding the SCO is restricted to the CPRO Ponds, the North Effluent Pond, the South Effluent Pond, and the Coal Pile Runoff Ditches.

The sediment samples collected from Hanaford Creek were either less than the MDL or less than the sediment cleanup objective for all constituents analyzed and are not discussed further in this section.

Chemical concentrations that are less than or equal to the CSL but greater than the sediment cleanup objective correspond to sediment quality that results in minor adverse effects to the benthic community. The only constituents that exceeded the sediment screening level for protection of the benthic community were chromium and mercury. The distribution of COCs in sediment exceeding the SCO is as follows:

- **Arsenic:** The distribution of arsenic impacts is displayed on Figure 45. Sediment sample result\s exceeding the SCO were observed in the CPRO Ponds 2 through 8, the North Effluent Pond, and the East Coal Pile Runoff Ditch.
- **Cadmium:** The distribution of cadmium impacts is displayed on Figure 46. Sediment sample results exceeding the SCO were observed in the CPRO Ponds 3 through 8 and the North Effluent Pond. The sediment samples collected in the Coal Pile Runoff Ditches were all less than the MDL.
- **Chromium:** The distribution of chromium impacts is displayed on Figure 47. Sediment samples that exceeded the SCO were observed in CPRO Ponds 3, 4, 6, 7, and 8 and the North Effluent Pond. Six of the eight samples that exceeded the SCO also exceeded the SCL for chromium.
- **Mercury:** The distribution of mercury impacts is displayed on Figure 48. Sediment samples that exceeded the SCO were observed in the CPRO Pond 5, the North Effluent Pond, the South Effluent Pond, and the East Coal Pile Runoff Ditch. All samples that exceeded the SCO also exceeded the SCL for mercury.
- **Nickel:** The distribution of nickel impacts is displayed on Figure 49. Sediment samples that exceeded the SCO were observed in the CPRO Pond 3, the North Effluent Pond, the South Effluent Pond, and the West Coal Pile Runoff Ditch.
- **Selenium:** The distribution of selenium impacts is displayed on Figure 50. Sediment samples that exceeded the SCO were observed in the CPRO Ponds 3 through 7 and the North Effluent Pond.

Suspected off-property contaminants:

Investigation of potential impacts from smoke stack deposition has not occurred and suspected contaminants of concern off-property include, dioxins and furans (D/F), semi-volatile organic compounds (SVOCs) and select metals.

Documents reviewed:

2025-05-13 ECY Draft RI Report_TransAlta_Centralia.pdf

CONTAMINANT GROUP	CONTAMINANT	*SOIL*	*GROUNDWATER*	*SURFACE WATER*	*AIR*	*SEDIMENT*	DESCRIPTION
Non-Halogenated Organics	Phenolic Compounds	Select	Select	Select		Select	Compounds containing phenols (Examples: phenol; 4-methylphenol; 2-methylphenol)
	Non-Halogenated Solvents	Select	Select	Select	Select	Select	Organic solvents, typically volatile or semi-volatile, not containing any halogens. To determine if a product has halogens, search HSDB (http://toxnet.nlm.nih.gov/cgi-bin/sis/htmlgen?HSDB) and look at the Chemical/Physical Properties, and Molecular Formula. If there is not a Cl, I, Br, F in the formula, it's not halogenated. (Examples: acetone, benzene, toluene, xylenes, methyl ethyl ketone, ethyl acetate, methanol, ethanol, isoprópranol, formic acid, acetic acid, stoddard solvent, Naptha). *Use this when TEX contaminants are present independently of gasoline.*
	Polynuclear Aromatic Hydrocarbons (PAH)	Select	**C**	Select	Select	Select	Hydrocarbons composed of two or more benzene rings.
	Tributyltin	Select	Select	Select		Select	The main active ingredients in biocides used to control a broad spectrum of organisms. Found in antifouling marine paint, antifungal action in textiles and industrial water systems. (Examples: Tributyltin; monobutyltin; dibutyltin)
	Methyl tertiary-butyl ether	Select	Select	Select	Select	Select	MTBE is a volatile oxygen-containing organic compound that was formerly used as a gasoline additive to promote complete combustion and help reduce air pollution.
	Benzene	Select	Select	Select	Select	Select	Benzene
	Other Non-Halogenated Organics	Select	Select	Select	Select	Select	TEX
	Petroleum Diesel	Select	**C**	Select		Select	Petroleum Diesel
	Petroleum Gasoline	Select	Select	Select	Select	Select	Petroleum Gasoline
	Petroleum Other	Select	**B**	Select		Select	Oil-range organics
Halogenated Organics (see notes at bottom)	PBDE	Select	Select	Select	Select	Select	Polybrominated di-phenyl ether
	Other Halogenated Organics	Select	Select	Select	Select	Select	Other organic compounds with halogens (chlorine, fluorine, bromine, iodine). search HSDB (http://toxnet.nlm.nih.gov/cgi-bin/sis/htmlgen?HSDB) and look at the Chemical/Physical Properties, and Molecular Formula. If there is a Cl, I, Br, F in the formula, it is halogenated. (Examples: Hexachlorobutadiene; hexachlorobenzene; pentachlorophenol)
	Halogenated solvents	Select	**C**	Select	Select	Select	PCE, chloroform, EDB, EDC, MTBE
	Polychlorinated Biphenyls (PCB)	Select	Select	Select	Select	Select	Any of a family of industrial compounds produced by chlorination of biphenyl, noted primarily as an environmental pollutant that accumulates in animal tissue with resultant pathogenic and teratogenic effects
	Dioxin/dibenzofuran compounds (see notes at bottom)	**B**	Select	Select	Select	Select	A family of more than 70 compounds of chlorinated dioxins or furans. (Examples: Dioxin; Furan; Dioxin TEQ; PCDD; PCDF; TCDD; TCDF; OCDD; OCDF). *Do not use for 'dibenzofuran', which is a non-chlorinated compound that is detected using the semivolatile organics analysis 8270*
Metals	Metals – Other	**C**	**C**	Select		**C**	Cr, Se, Ag, Ba, Cd
	Lead	Select	Select	Select		Select	Lead
	Mercury	Select	Select	Select	Select	**C**	Mercury
	Arsenic	**C**	**C**	Select		Select	Arsenic
Pesticides	Non-halogenated pesticides	Select	Select	Select	Select	Select	Pesticides without halogens (Examples: parathion, malathion, diazinon, phosmet, carbaryl (sevin), fenoxycarb, aldicarb)
	Halogenated pesticides	Select	Select	Select	Select	Select	Pesticides with halogens (Examples: DDT; DDE; Chlordane; Heptachlor; alpha-beta and delta BHC; Aldrin; Endosulfan, dieldrin, endrin)

CONTAMINANT GROUP	CONTAMINANT	SOIL	GROUNDWATER	SURFACE WATER	AIR	SEDIMENT	DESCRIPTION
Other Contaminants	Radioactive Wastes	Select	Select	Select	Select	Select	Wastes that emit more than background levels of radiation.
	Conventional Contaminants, Organic	Select	Select	Select		Select	Unspecified organic matter that imposes an oxygen demand during its decomposition (Example: Total Organic Carbon)
	Conventional Contaminants, Inorganic	Select	Select	Select	Select	Select	Non-metallic inorganic substances or indicator parameters that may indicate the existence of contamination if present at unusual levels (Examples: Sulfides, ammonia)
	Asbestos	Select	Select	Select	Select	Select	All forms of Asbestos. Asbestos fibers have been used in products such as building materials, friction products and heat-resistant materials.
	Other Deleterious Substances	Select	Select	Select		Select	Other contaminants or substances that cause subtle or unexpected harm to sediments (Examples: Wood debris; garbage (e.g., dumped in sediments))
	Benthic Failures	Select	Select	Select		Select	Failures of the benthic analysis standards from the Sediment Management Standards.
	Bioassay Failures	Select	Select	Select		Select	For sediments, a failure to meet bioassay criteria from the Sediment Management Standards. For soils, a failure to meet TEE bioassay criteria for plant, animal or soil biota toxicity.
Reactive Wastes	Unexploded Ordinance	Select	Select	Select	Select	Select	Weapons that failed to detonate or discarded shells containing volatile material.
	Other Reactive Wastes	Select	Select	Select	Select	Select	Other Reactive Wastes (Examples: phosphorous, lithium metal, sodium metal)
	Corrosive Wastes	Select	Select	Select	Select	Select	Corrosive wastes are acidic or alkaline (basic) wastes that can readily corrode or dissolve materials they come into contact with. Wastes that are highly corrosive as defined by the Dangerous Waste Regulation (WAC 173-303-090(6)). (Examples: Hydrochloric acid; sulfuric acid; caustic soda)

(fill in contaminant matrix above with appropriate status choice from the key below the table)

Status choices for contaminants	
Contaminant Status	**Definition**
B— Below Cleanup Levels (Confirmed)	The contaminant was tested and found to be below cleanup levels. (Generally, we would not enter each and every contaminant that was tested; for example if an SVOC analysis was done we would not enter each SVOC with a status of "below". We would use this for contaminants that were believed likely to be present but were found to be below standards when tested
S— Suspected	The contaminant is suspected to be present; based on some knowledge about the history of the site, knowledge of regional contaminants, or based on other contaminants known to be present
C— Confirmed Above Cleanup Levels	The contaminant is confirmed to be present above any cleanup level. For example—above MTCA method A, B, or C; above Sediment Quality Standards; or above a presumed site-specific cleanup level (such as human health criteria for a sediment contaminant).
RA— Remediated - Above	The contaminant was remediated, but remains on site above the cleanup standards (for example—capped area).
RB— Remediated - Below	The contaminant was remediated, and no area of the site contains this contaminant above cleanup standards (for example—complete removal of contaminated soils).

Halogenated chemicals and solvents: Any chemical compound with chloro, bromo, iodo or fluoro is halogenated; those with eight or fewer carbons are generally solvents (e.g. halogenated methane, ethane, propane, butane, pentane, hexane, heptane or octane) and may also be used for or registered as pesticides or fumigants. Most are dangerous wastes, either listed or categorical. Organic compounds with more carbons are almost always halogenated pesticides or a contaminant or derivative. Referral to the HSDB is recommended if you are unfamiliar with a chemical name or compound, as it contains useful information about synonyms, uses, trade names, waste codes, and other regulatory information about most toxic or potentially toxic chemicals.

Dibenzodioxins and dibenzofurans are normalized to a combined equivalent toxicity based on 2,3,7,8-tetrachloro-p-dibenzodioxin as set out in WAC 173-340-708(8)(d) and in the Evaluating the Toxicity and Assessing the Carcinogenic Risk of Environmental Mixtures using Toxicity Equivalency Factors Focus Sheet (https://fortress.wa.gov/ecy/clarc/FocusSheets/tef.pdf). Results may be reported as individual compounds and isomers (usually lab results), or as a toxic equivalency value (reports).

FOR ECOLOGY II REVIEWER USE ONLY (For Listing Sites):

How did the Site come to be known ☒ **Site Discovery (received a report)** **5/14/2025** (Date Report Received)
☐ **ERTS Complaint**
☐ **Other (please explain):** Click to enter text.

Does an Early Notice Letter need to be sent: ☒ Yes ☐ No
If *No*, please explain why: Click to enter text.

NAICS Code (if known): **221112**
Otherwise, briefly explain how property is/was used (i.e., gas station, dry cleaner, paint shop, vacant land, etc.):
Power Generation Facility – Coal burning

Site Unit(s) to be created (Unit Type): ☒ Upland (includes VCP & LUST) ☒ Sediment
If multiple Unites needed, please explain why: Click to enter text.

Cleanup Process Type (for the Unit):
☐ No Process
☐ Voluntary Cleanup Program
☐ Federal-supervised or conducted
☐ Independent Action
☒ Ecology-supervised or conducted

Site Status:
☒ Awaiting Cleanup
☐ Cleanup Started
☐ No Further Action Required
☐ Construction Complete – Performance Monitoring
☐ Cleanup Complete – Active O&M/Monitoring

Model Remedy Used? ☐
If yes, was this a transformer spill? ☐

Site Manager (Default Tom Middleton) Click to enter text.

Specific confirmed contaminants include:
Metals in Soil
Metals, DRO, VOCs in Groundwater
Metals, in Other (specify matrix: Sediment

Facility/Site ID No. (if known):
94772166
Cleanup Site ID No. (if known):
Click to enter text.

COUNTY ASSESSOR INFO: Please attach to this report a copy of the tax parcel/ownership information for each parcel associated with the site, as well as a parcel map illustrating the parcel boundary and location.

Additional or Supplemental Information for Observations Page

Please use this box for any text that requires special formatting

Click to enter text.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-54:
Centralia Hazardous Substances Liability Determination (Oct. 2025)

COPY

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
Southwest Region Office
PO Box 47775 • Olympia, WA 98504-7775 • 360-407-6300

Tuesday, October 14, 2025

Mickey Dreher
TransAlta Centralia Generation LLC
913 Big Hanaford Rd,
Centralia, WA 98531-9101

Re: Final Determination of Liability for Release of Hazardous Substances at the following Contaminated Site:

- **Site Name:** Centralia Steam Plant
- **Site Address:** 913 Big Hanaford Rd, Centralia, WA 98531-9101
- **Cleanup Site ID:** 17302
- **Facility/Site ID:** 94772166

Dear Mickey Dreher:

On September 4, 2025, the Department of Ecology (Ecology) sent you written notice of our preliminary determination that TransAlta Centralia Generation LLC is a potentially liable person (PLP) for a release of hazardous substances at the Centralia Steam Plant facility (Site). On October 8, 2025, Ecology received your written notice accepting your status as a PLP for the Site and waiving your opportunity to comment.

Based on available information, Ecology finds that credible evidence exists that TransAlta Generation LLC is liable for a release of hazardous substances at the Site. On the basis of this finding, Ecology has determined that TranAlta Generation LLC is a PLP with regard to the Site.

The purpose of the Model Toxics Control Act (MTCA) is to identify, investigate, and cleanup facilities where hazardous substances have been released. Liability for environmental contamination under MTCA is strict, joint and several (RCW 70.105D.040(2)). Ecology ensures that contaminated sites are investigated and cleaned up to the standards set forth in the MTCA statue and regulations. Ecology has determined that it is in the public interest for remedial actions to take place at this Site. Ecology will contact you regarding the actions necessary for the TransAlta Generation LLC to bring about the prompt and thorough cleanup of hazardous substances at this Site. Failure to cooperate with Ecology or comply with MTCA in this matter will result in Ecology employing enforcement tools as it deems necessary and appropriate. This includes, but is not limited to, the issuance of an administrative order. Failure to comply with such an order may result in a fine of up to $25,000 per day and liability for up to three times the costs incurred by the state (RCW 70.105D.050(1)).

Your rights and responsibilities as a PLP are outlined in Chapter 70.105D RCW, and Chapters 173-340 and 173-204 WAC. Ecology's cleanup project manager for the Site, Thomas Middleton, will contact you with information about how Ecology intends to proceed with the cleanup.

If you have any questions regarding this notice, please contact Thomas Middleton at (360) 999-9594 or Thomas.middleton@ecy.wa.gov.

Sincerely,

Marian L. Abbett

Marian Abbett
Section Manager
Toxics Cleanup Program, SWRO

By certified mail:9489 0090 0027 6341 0494 07

cc: Conrad Wieclaw, Vincent Light, (Transalta): Conrad_Wieclaw@transalta.com
Dan Lawler,Office of the Attorney General: dan.lawler@atg.wa.gov
Ivy Anderson, Office of the Attorney General: Ivy.Anderson@atg.wa.gov
Tom Middleton, SWRO TCP Cleanup Project Manager: thomas.middleton@ecy.wa.gov
Bobbak Talebi, SWRO Regional Director: bobbak.talebi@ecy.wa.gov
Ecology Site File

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-55:
Emissions Performance Standard

Emissions Performance Standard (EPS)

Feedback

Emissions Performance Standard (EPS)

The emissions performance standard (EPS) is a set of state-imposed rules to a limit the amount of CO2 that each power station may emit to atmosphere.

The emissions performance standard (EPS) is a set of state-impose rules to limit the amount of greenhouse gas emissions each baseload power plant can release into the air.

Every five years, our office adopts rules on the average available greenhouse gas emissions output by surveying new combined-cycle natural gas thermal electric generation turbines. The turbines need to be commercially available, offered for sale by manufacturers and purchased in the United States. Then we determine the average rate of emissions of greenhouse gases for them.

Baseload generation limits and utility investment restrictions

Baseload generation, which refers to the minimum amount of continuous electricity supply that is needed to meet the basic demand of the power grid over a 24-hour period, is considered to be a generating unit operating at a capacity factor of 60 or greater percent. This means a facility that produces energy each year equaling at least 60 percent of the energy it could produce at continuous full power operation for the same period.

Utilities may not enter into long-term contracts (five or more years) with a baseload generating facility, nor can utilities invest in a facility, when the greenhouse gas emissions of the facility exceed the standard.

The standard applies to all investor and consumer-owned utilities in the state. Renewable and nuclear-powered electricity are exempt, as are long-term commitments with the Bonneville Power Administration.

Feedback

The performance standard was last updated in January 2025. The new rule lowers the average estimated greenhouse gas emissions rate of combined-cycle natural gas power plants from 925 to 876 pounds per megawatt-hour. This updated emissions rate of greenhouse gas emissions will be used by the Department of Ecology (Ecology) and Energy Facility Site Evaluation Council (EFSEC) to apply Washington's emissions standard as required by state law (**Chapter 80.80 RCW**).

Power plants must meet the greenhouse gas emission standards or capture and store their carbon pollution under this rule. The Department of Ecology and local clean air agencies regulate small plants that generate megawatts of electricity (MWe), but less than 350 MWe. The Energy Facility Site Evaluation Council (EFSEC) regulates larger plants that generate more than 350 MWe.

Rulemaking

Commerce began its most recent rulemaking process in February 2024, and since then, the agency held three public workshops and three technical advisory group meetings. Commerce received and responded to comments, incorporating changes based on them into the rulemaking process. The public workshops and advisory team meetings were well-attended. Commerce received two public comments.

The latest rule lowers the average available greenhouse gas emissions output estimate of combined-cycle natural gas facilities from 925 lb/MWh to 876 lb/MWh. The updated average rate of greenhouse gas emissions will be used by the Department of Ecology (Ecology) and Energy Facility Site Evaluation Council (EFSEC) to implement Washington's baseload electric generation emissions performance standard as provided for under **Chapter 80.80 RCW**.

- **Final rules for WAC 194-26-020**

For questions related to the rulemaking process, please contact Aaron Tam, Energy Utility Data Specialist, at **energydata@commerce.wa.gov** or by calling 206-454-2251.

Resources

- **Final rules for WAC 194-26-020**
- **RCW 80.80.040**
- **WAC 194.26.010 – Authority**
- **WAC 194.26.020 – Average available greenhouse gas emissions output**
- **Department of Ecology's power plant greenhouse gas standards webpage**

Feedback

Page last updated: May 21, 2025

Contact

Austin Scharff, Senior Energy Policy Specialist
Austin.Scharff@commerce.wa.gov

Aaron Tam, Data Specialist
Aaron.Tam@commerce.wa.gov

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-56:
Puget 2024 Annual EEI Report

PUGET SOUND ENERGY

Annual Energy and Emissions Intensity ("EEI") Metrics Report

Pursuant to WAC 480-109-300

May 31, 2025

<u>**Table of Contents**</u>

PSE's Annual Energy and Emissions Intensity (EEI) Metrics Report for operating year 2024

Section 1: Executive Summary

Compared to the 2023 operating year, Puget Sound Energy's (PSE's) 2024 carbon dioxide equivalent (CO_2e) emissions intensity from total electricity delivered to customers decreased from 877.5 lb/MWh to 830.3 lb/MWh.[1] This report provides the metrics, analyses, and descriptions behind that change. Further, it demonstrates that PSE delivers electricity to customers from a combination of sources that the Company owns and purchases from other providers via firm contracts or the spot market.

Per the requirements of WAC 480-109-300, PSE submits the following report outlining its energy and emissions intensity metrics for the previous ten years (reporting period). This report includes the following metrics for all PSE generating resources serving customers:

- Average megawatt-hours (aMWh) per residential customer
- Average megawatt-hours (aMWh) per commercial customer
- Megawatt-hours (MWh) per capita
- Annual carbon dioxide equivalent (CO_2e) emissions measured in metric tons
- Comparison of annual CO_2e emissions to CO_2 emissions in 1990

PSE and the other utilities purchase a percentage of their energy to serve native load from the spot market. The generation sources from purchases made on the spot market are unknown. Therefore, this report also includes a subset of metrics for spot market purchases based on the unspecified emission rate factor provided by the Washington State Department of Ecology ("Ecology"). Those metrics include:

- Annual CO_2e emissions (metric tons) from unknown generation sources
- Annual megawatt-hours (MWh) delivered to retail customers from unknown generation sources
- Percentage of load served by unknown generation sources

In addition to the raw data included in Attachment A to this report, the tables and sections below provide trend analysis, narrative descriptions, and graphics to help contextualize PSE's data and trends for the reporting period. Table 1 below summarizes PSE's greenhouse gas

[1] Beginning in 2022, adjusted to apply Bonneville Power Administration (BPA) Asset-Controlling Supplier (ACS) System emission factors for BPA specified purchases. See Sections 3 and 4 for more information.

(GHG) emissions intensity and energy metrics for the calendar year 2024. Summaries of the previous nine years in the reporting period are included in Attachment A to this report. Section 2 below provides a 10-year "lookback" analysis of the reporting period (to the operating year 2015) of the metrics mentioned above and benchmarks those metrics to a 1990 emissions baseline. Section 3 provides a discussion of the trends observed in the metrics and the broader regional market. Section 4 includes appendices that provide more detail on the methodologies used in this report.

Summarized in Table 1 and narrative below are PSE's 2024 energy and emissions intensity metrics. The energy intensity metrics represent the metered sale of energy to customers (by class) as reported under the Federal Energy Regulatory Commission (FERC) Form-1 protocols, i.e., Total Load Served. Busbar energy tallies represent the total load PSE served (to Washington) generated and purchased, net of bilateral sales, as reported in PSE's Energy Accounting (EA) database, i.e., Busbar MWh.

Table 1. 2024 Energy and Intensity Metrics

Utility :	Puget Sound Energy	
Reporting for year :	2024	**MWh per Capita**
Population Served :	2,712,488	**7.80**

Energy Intensity Metrics

	MWh at Meter	MWh Proportion	Customer Count	**MWh per Customer**
Residential Customers	11,462,977	54.2%	1,091,599	**10.5**
Commercial Customers	8,570,573	40.5%	134,993	**63.5**
Industrial Customers	1,057,368	5.0%		
Other Customers	77,822	0.4%		
Total Load Served	21,168,740	100.0%		

Emissions Intensity Metrics

	Busbar MWh	Percent of Total Load	**Metric Tons CO_2e**	
Known Resources Serving WA				
EPA Methodology	25,508,769	114.9%	9,623,768	
EIA Methodology	0	0.0%	0	
Unknown Resources Serving WA	(3,299,563)	**-14.9%**	(1,259,530)	**% of 1990 CO_2**
Total Busbar MWh	**22,209,206**	Total Metric Tons:	**8,364,238**	**132.7%**

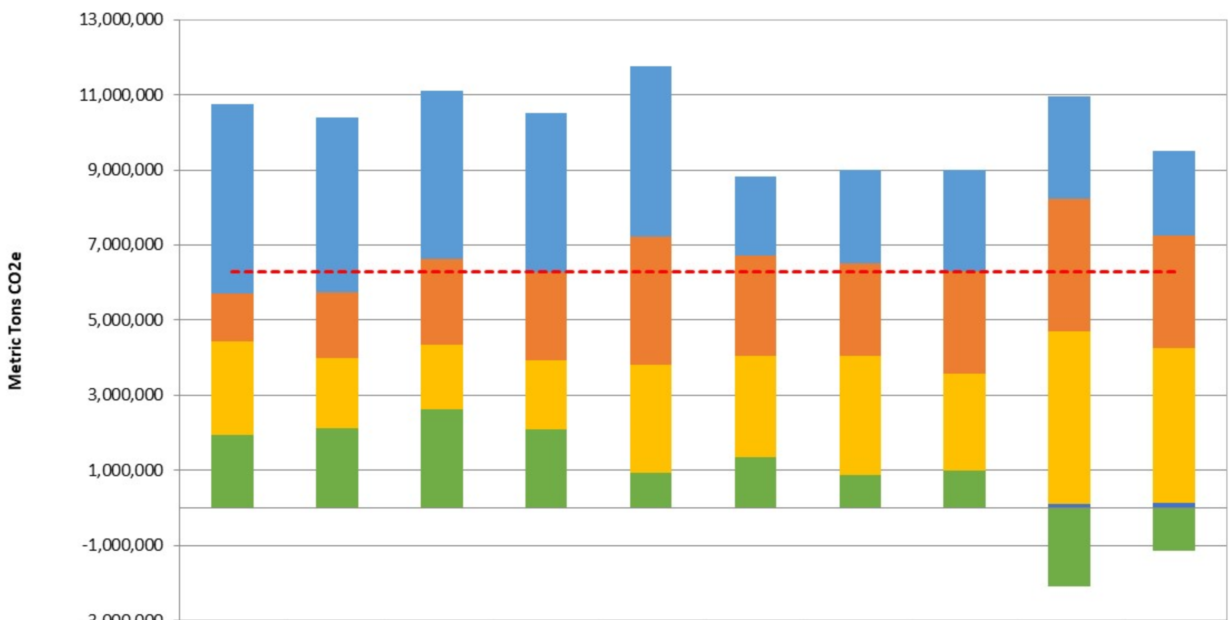
1990 Metric Tons CO_2	6,301,363

Section 2: Prior 10-year annual metrics for all generating resources serving Washington customers

Figure 1 provides a comparison of annual PSE CO_2e emissions measured in metric tons from generation sources for the previous 10 years. Figure 1 also includes a 1990 emissions baseline.

Until 2020, WAC 480-109-300 specified that the EEI report only include CO_2 output. In 2020, as a result of rulemaking conducted to implement the Clean Energy Transformation Act (CETA), revised WAC 480-109-300 now requires all greenhouse gas emissions in the EEI report be based on CO_2e. This change means the inclusion of methane (CH4) and nitrous oxide (N2O) as CO_2e[2] for all resources and years presented in this report.

Figure 1. Total Emissions by Resource Type

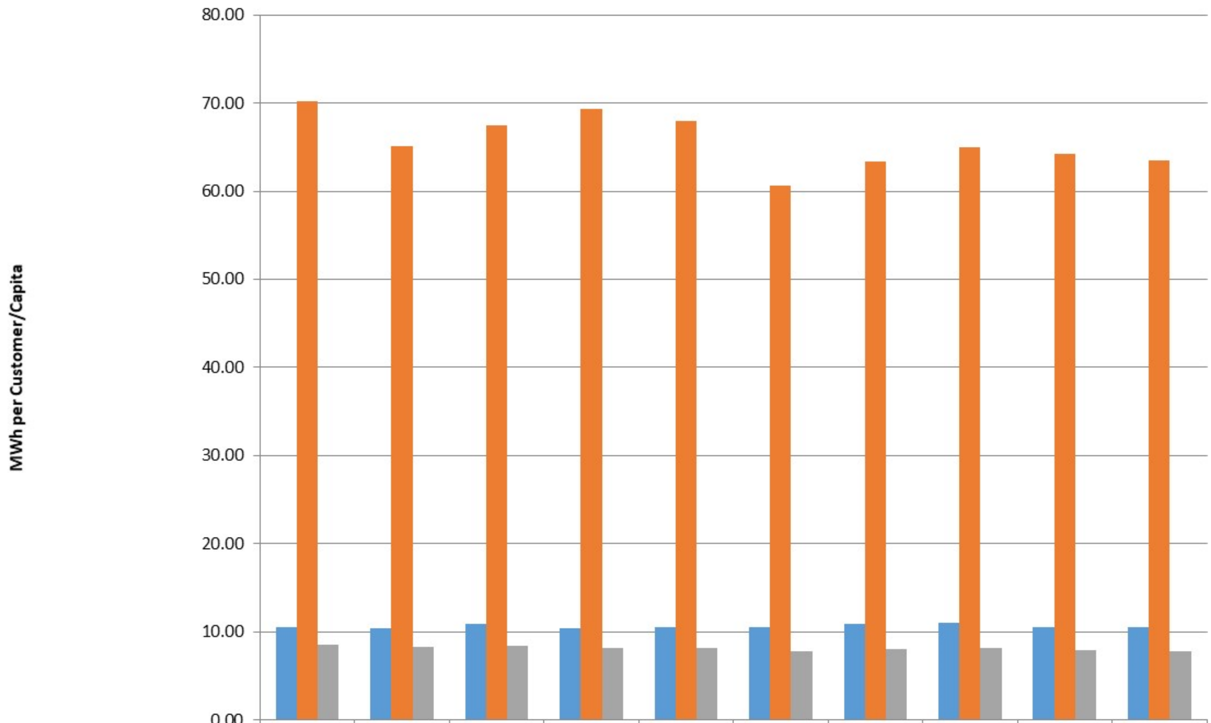


	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Owned Coal	5,034,544	4,642,921	4,486,832	4,255,201	4,531,772	2,089,805	2,508,424	2,684,409	2,741,750	2,230,496
Firm Coal	1,280,440	1,746,188	2,271,968	2,348,792	3,395,867	2,671,660	2,459,358	2,750,063	3,536,340	3,015,251
Owned Diesel	253	155	335	62	155	514	439	747	34	305
Owned Gas	2,487,336	1,872,826	1,730,673	1,825,412	2,874,183	2,703,673	3,170,392	2,566,071	4,578,453	4,118,746
Firm Gas	167	86							113,329	131,152
Unspecified	1,935,514	2,119,604	2,625,679	2,097,895	950,430	1,348,716	873,099	999,377	-2,100,695	-1,131,712
1990 Baseline	6,301,363	6,301,363	6,301,363	6,301,363	6,301,363	6,301,363	6,301,363	6,301,363	6,301,363	6,301,363

2 Principle combustible constituents in natural gas and coal are carbon, hydrogen, and their compounds, and in the combustion process, these compounds and elements oxidize to CO_2 and water vapor. However, small amounts of methane (CH_4) result from incomplete fuel combustion, and nitrous oxide (N_2O) formation results from post-combustion thermal reactions.

Figure 2 provides a comparison of the average MWh per residential customer, average MWh per commercial customer, and MWh per capita delivered in each of the years during the reporting period in PSE's service territory.

Figure 2. Energy Intensity Metrics



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
MWh / Residential Customer	10.47	10.40	10.89	10.39	10.49	10.56	10.90	11.03	10.57	10.50
MWh / Commercial Customer	70.25	65.07	67.49	69.33	68.01	60.66	63.37	64.99	64.28	63.49
MWh per capita	8.48	8.29	8.41	8.18	8.15	7.75	8.04	8.17	7.91	7.80

Figure 3 provides a comparison of the ratios of PSE's annual CO_2e emissions from known sources for the reporting period compared to CO_2 emission in 1990.

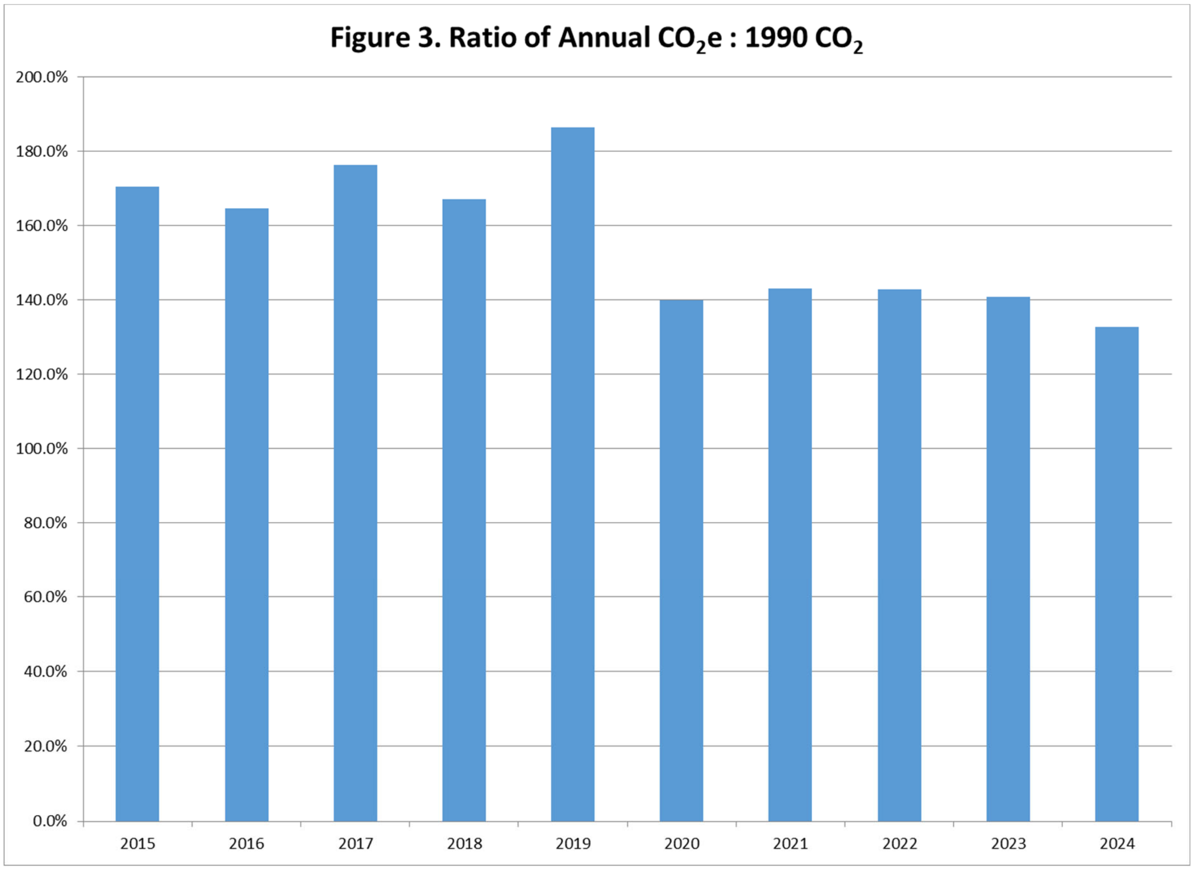
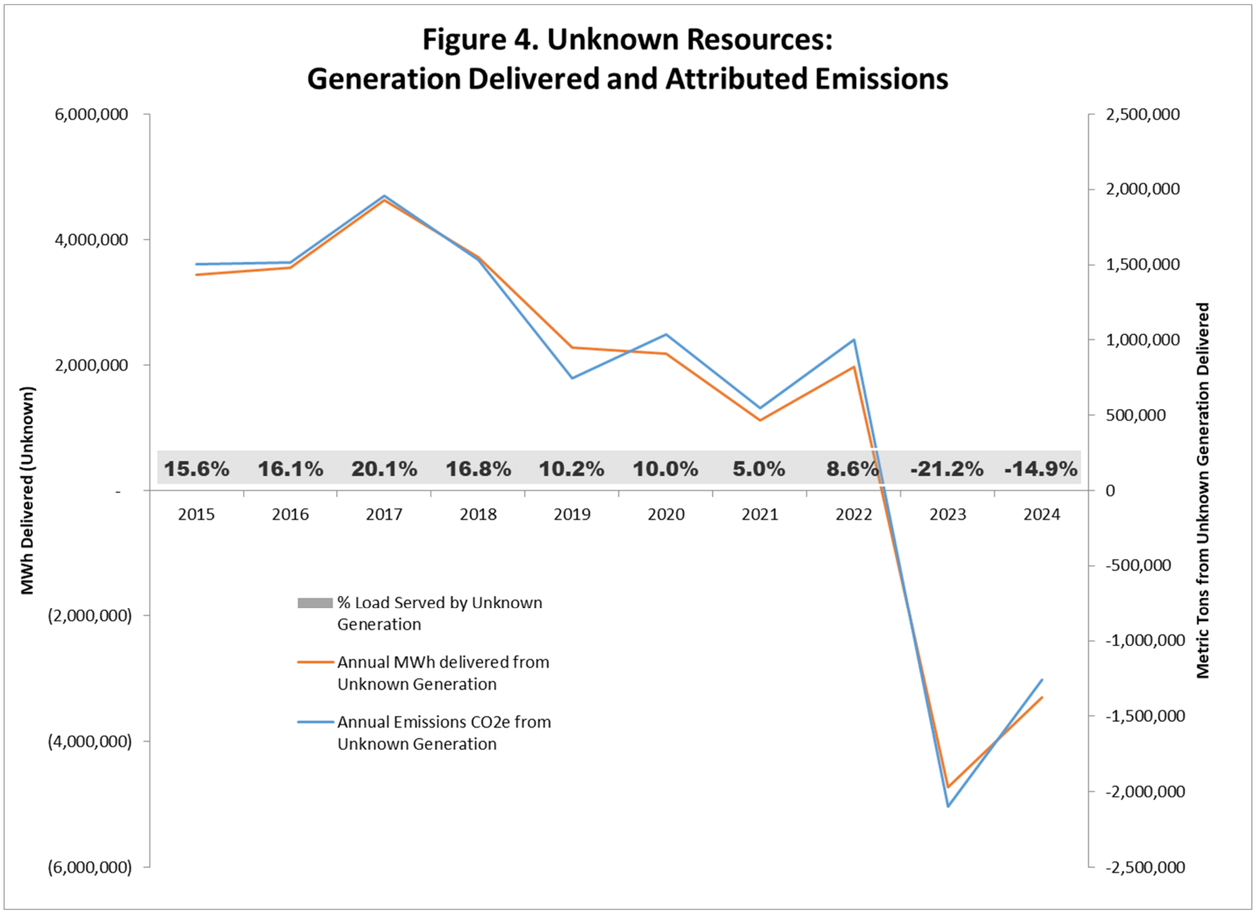


Figure 4 provides a 10-year comparison of generation delivered to PSE from unknown sources and the attributed emissions. Those metrics include annual CO_2e emissions (metric tons), annual MWh delivered to retail customers, and the percentage of load served. As discussed in the executive summary, the generation sources and attributed emissions for spot market purchases are unknown. Therefore, emissions factors for each of the previous ten years in the reporting period were applied according to methodology provided by the Department of Ecology.



Section 3: Trend Analysis

This section addresses the requirement in WAC 480-109-300(5) to include narrative text describing trends and an analysis of the likely causes of changes, or lack of changes, in the metrics.

Electric Supply

In 2024, PSE's electric power resources, which include company-owned or controlled resources and those under long-term contract, had a total capacity of approximately 6,524 megawatts (MW). PSE purchases electric energy under long-term firm-purchased power contracts with other utilities and marketers in the Western Interconnection. PSE is generally not obligated to make payments under these contracts unless power is delivered.

Energy supply and demand balance across the Western Interconnection is maintained on a second-to-second basis, and PSE dispatches its resources based on market prices and other system constraints in the Interconnection. Generally speaking, when the dispatch cost of a specific PSE-owned unit is lower than the market price, it is economic for the unit to run. Net revenue resulting from sales of electricity from PSE-dispatched resources result in net revenue that is credited back to customers to reduce rates. When the cost to run the PSE-owned unit is greater than the market price, the units are not dispatched. PSE may also dispatch resources in real-time based on dispatch operating instructions issued by the California Independent System Operator (CAISO) in its Energy Imbalance Market (EIM). Dispatch decisions are independent of the demand by PSE's customers. If PSE's customers need power when its units are uneconomic to run, PSE purchases the energy from wholesale markets – other utilities or registered power marketers with energy to sell. If PSE's generation is dispatched and there is a surplus above PSE's customers' needs, that surplus will be sold in the wholesale market (net revenue from such sales is credited back to customers through rates), meaning whatever is happening to PSE's load is unrelated. The primary driver of generation dispatch is whether a generator's variable cost of dispatch is lower than the market price.

PSE tracks its firm and non-firm power transactions in its Energy Accounting (EA) database on a calendar year basis. Table 2 shows all firm energy transactions made in 2024, including the total dispatch of all of PSE-owned units. Emissions from PSE's units and from each firm purchase are calculated using the methodologies described in Appendix 2.1 and 2.2, respectively. For unspecified electricity purchases, PSE uses the emissions intensity metrics according to WAC

480-109-300(4)[3]. PSE employed Commission Staff's net-by-counterparty approach to calculate emissions from its non-firm (unspecified) power transactions. Details of these transactions are presented in Table 3, and the calculation methodology is described in Appendix 2.3. Staff requested in its compliance letter to PSE's 2017 EEI report that the Company explain how PSE determines whether a source is known or unknown. Staff correctly assumes that PSE classifies non-unit specific purchases as unknown sources. PSE-owned resources and unit-specific firm deliveries are classified as known sources because their fuel source is known and reported in the U.S. Energy Information Administration (EIA) databases, described in Appendix 2.1 and 2.2.

Table 2. Known Resources Serving WA Customers

Resource	Generation / Purchase WA MWh	Sales WA MWh	Metric Tons CO_2e	Type	Fuel
Lower Baker	326,698		0	Own	Hydro
Snoqualmie Falls #1	65,857		0	Own	Hydro
Snoqualmie Falls #2	158,872		0	Own	Hydro
Upper Baker	317,830		0	Own	Hydro
Colstrip 3 & 4	2,195,159		2,230,496	Own	Coal
Crystal Mountain	366.2		305	Own	Diesel
Encogen	763,946		364,444	Own	Gas
Ferndale	1,684,142		804,020	Own	Gas
Freddie #1	856,249		333,786	Own	Gas
Fredonia	555,781		367,670	Own	Gas
Frederickson	88,924		63,613	Own	Gas
Goldendale	2,099,550		780,985	Own	Gas
Mint Farm	2,695,425		924,443	Own	Gas
Sumas	674,253		316,436	Own	Gas
Whitehorn	230,887		163,349	Own	Gas
Hopkins Ridge (W184)	411,010		0	Own	Wind
Lower Snake River	873,275		0	Own	Wind
Wild Horse (W183)	636,124		0	Own	Wind
Sierra Pacific Industries	128,427		0	Bundled PPA	Biomass
Bio Energy Washington (BEW)	77		0	Qualifying Facility	Biogas

[3] Bonneville Power Administration (BPA) Asset-Controlling Supplier (ACS) System emission factors are used for BPA specified purchase claims beginning in reporting year 2022 (https://apps.ecology.wa.gov/publications/documents/2302002.pdf). For all other unspecified electricity purchases, the default emission factor provided by the Washington State Department of Ecology is used (RCW 19.405.070).

Resource	Generation / Purchase WA MWh	Sales WA MWh	Metric Tons CO_2e	Type	Fuel
Edaleen Dairy LLC	3,508		0	Qualifying Facility	Biogas
Emerald City Renewables	32,053		0	Qualifying Facility	Biogas
Farm Power Rexville LLC	3,099		0	Qualifying Facility	Biogas
Rainier Bio Gas	832		0	Qualifying Facility	Biogas
VanderHaak Dairy Digester	2,451		0	Qualifying Facility	Biogas
Transalta Centralia Generation LLC	2,700,452		3,015,251	Unbundled PPA	Coal
Transalta Centralia Generation LLC	292,490		127,818	Unbundled PPA	Market
Chelan County PUD #1	123,200		0	Bundled PPA	Hydro
Chelan PUD - RI & RR	1,632,424		0	Bundled PPA	Hydro
Chelan PUD - Slice 35	323,790		0	Bundled PPA	Hydro
Chelan PUD - Slice 38	334,072		0	Bundled PPA	Hydro
Black Creek Hydro Inc	11,311		0	Qualifying Facility	Hydro
Koma Kulshan Associates	24,725		0	Qualifying Facility	Hydro
Nooksack	20,084		0	Qualifying Facility	Hydro
Skookumchuck Hydro	2,157		0	Qualifying Facility	Hydro
Sygitowicz Creek	594		0	Qualifying Facility	Hydro
Twin Falls Hydro	62,947		0	Qualifying Facility	Hydro
Weeks Falls	11,521		0	Qualifying Facility	Hydro
Douglas PUD - Wells Project	535,293		0	Unbundled PPA	Hydro
Grant PUD - Priest Rapids Project	336,069		0	Unbundled PPA	Hydro
KERR DAM-ENERGY KEEPER	351,282		0	Unbundled PPA	Hydro
Powerex Seasonal Capacity	1,216,000		0	Unbundled PPA	Hydro
HF Sinclair (Mar Pt)	656,794		223,636	Qualifying Facility	Gas
CAMAS SOLAR	9,844		0	Community Solar	Solar
Penstemon Solar	10,843		0	Community Solar	Solar
URTICA SOLAR	10,646		0	Community Solar	Solar
Bonney Lake CS	514		0	CS Generation	Solar
Olympia High School CS	245		0	CS Generation	Solar
Pine Lake Middle School CS	145		0	CS Generation	Solar
Lund Hill Solar, LLC	361,485		0	Green Direct	Solar
CC Solar 1 and CC Solar 2	28		0	Qualifying Facility	Solar

Resource	Generation / Purchase WA MWh	Sales WA MWh	Metric Tons CO_2e	Type	Fuel
Ikea Solar	13		0	Qualifying Facility	Solar
Lake Washington -- Finn Hill	287		0	Qualifying Facility	Solar
Port of Coupeville	49		0	Qualifying Facility	Solar
Schedule 667 Solar Energy Credit	168		0	Qualifying Facility	Solar
TACOMA GLASS	174		0	Qualifying Facility	Solar
Avangrid Renewable (Golden Hills)	685,096		0	Bundled PPA	Wind
Clearwater Wind	1,304,894		0	Bundled PPA	Wind
Klondike Wind Power III	123,482		0	Bundled PPA	Wind
Skookumchuck Wind PPA	416,933		0	Green Direct	Wind
Swauk Wind	2,363		0	Green Power Program	Wind
California ISO		-374,270	0	EIM Sales and Purchases	Hydro
California ISO		-212,412	-92,484	EIM Sales and Purchases	Gas
California ISO		-271,754	0	EIM Sales and Purchases	Wind

Table 3. Unknown Resources Serving WA Customers

Counterparty	Type	Energy Purchased (MWh)	Energy Sold (MWh)	Net Purchase (MWh)	Rate $mtCO_2e/MWh$	Metric Tons CO_2e
BPA Purchases	Market	792,762	0	792,762	--	208,238.7
BPA Sales	Market	0	-358,111	-358,111	--[4]	-156,495
Avista Corp. WWP Division	Market	14,754	-76,585	-61,831	0.377	-23,327
Avista Nichols Pump	Interchange In	13,837	0	13,837	0.437	6,046.8
BASIN ELECTRIC POWER	Market	0	-4,022	-4,022	0.377	-1,517
BC Hydro (Point Roberts)	Unbundled PPA	20,596	0	20,596	0.437	9,000.4
BHE Power Watch, LLC	Market	0	-3	-3	0.377	-1
BP Energy Co.	Market	1,805	-547,122	-545,317	0.377	-205,733
British Columbia Transmission Corp	Market	0	-8	-8	0.377	-3
Brookfield Energy Marketing	Market	61,600	-242,601	-181,001	0.377	-68,287

[4] BPA specified purchases use 0.0174; BPA unspecified purchases use 0.437.

Counterparty	Type	Energy Purchased (MWh)	Energy Sold (MWh)	Net Purchase (MWh)	Rate $mtCO_2e/MWh$	Metric Tons CO_2e
California ISO	EIM Purchases	1,230,919	0	1,230,919	0.437	537,911.7
California ISO	EIM Sales	0	-37,873	-37,873	0.377	-14,288
California ISO	EIM Sales to CA	0	-173	-173	0.377	-65
California ISO	Purchases	108,868	0	108,868	0.437	47,575.3
California ISO	Sales	0	0	0	0.377	-0.1
California ISO	Sales to CA	0	-2,244	-2,244	0.377	-847
Chelan County PUD #1	Market	19,602	-3,606	15,996	0.437	6,990.3
Citigroup Energy Inc	Market	47,676	-773,028	-725,352	0.377	-273,656
Clatskanie PUD	Market	2,671	-3,322	-651	0.377	-246
Conoco, Inc.	Market	809,406	-594,187	215,219	0.437	94,050.7
CONSTELLATION ENERGY	Market	53,713	-58,364	-4,651	0.377	-1,755
CP Energy Marketing (Epcor)	Market	6,209	-6,572	-363	0.377	-137
Deviation	System Deviation	0	-3,994	-3,994	0.377	-1,507
DYNASTY POWER INC	Market	597	-312,664	-312,067	0.377	-117,734
EDF Trading NA LLC	Market	22,537	-6,288	16,249	0.437	7,100.8
Energy Keepers Inc.	Market	400	-1,000	-600	0.377	-226
Eugene Water & Electric	Market	7,736	-40,653	-32,917	0.377	-12,419
Grant County PUD #2	Market	6	0	6	0.437	2.6
GRIDFORCE ENERGY MANAGEMENT, LLC.	Market	10	-761	-751	0.377	-283
Iberdrola Renewables (PPM Energy)	Market	268,684	-802,903	-534,219	0.377	-201,546
Idaho Power Company	Market	5,669	-9,479	-3,810	0.377	-1,437
J. Aron & Company	Market	0	-400	-400	0.377	-151
MERCURIA ENERGY	Market	20,852	-228,460	-207,608	0.377	-78,325
Merrill Lynch Commodities	Market	354,833	-790,692	-435,859	0.377	-164,438
Morgan Stanley CG	Market	320,484	-351,762	-31,278	0.377	-11,800
Natur Ener USA	Market	0	-20	-20	0.377	-8
Nevada Energy	Market	0	0	0	0.377	0.0
Nevada Power Company	Market	50	-155	-105	0.377	-40
New Mexico, Public Service Company	Market	90	0	90	0.437	39.3
Northwestern Energy	Market	6,944	-23,827	-16,883	0.377	-6,369
NRG Business Marketing LLC DECM	Market	0	-400	-400	0.377	-151
Pacific Gas & Elec - Exchange	Interchange In-0ut	413,000	-413,000	0	0.377	0.0

Counterparty	Type	Energy Purchased (MWh)	Energy Sold (MWh)	Net Purchase (MWh)	Rate $mtCO_2e/MWh$	Metric Tons CO_2e
Pacificorp	Market	8,216	-57,809	-49,593	0.377	-18,710
PHILLIPS 66 ENERGY	Market	7,194	-268,574	-261,380	0.377	-98,612
Portland General Electric	Market	24,398	-149,315	-124,917	0.377	-47,128
Powerex Corp.	Market	46,199	-965,399	-919,200	0.377	-346,789
Rainbow Energy Marketing	Market	2,137	-4,796	-2,659	0.377	-1,003
Sacramento Municipal	Market	50	-60	-10	0.377	-4
Salt River Project Power	Market	6	-5	1	0.437	0.4
Seattle City Light Marketing	Market	27,681	-51,598	-23,917	0.377	-9,023
Shell Energy (Coral Pwr)	Market	109,261	-160,998	-51,737	0.377	-19,519
Snohomish County PUD #1	Market	7,005	-24,295	-17,290	0.377	-6,523
Tacoma Power	Market	14,683	-4,292	10,391	0.437	4,540.9
The Energy Authority	Market	26,603	-127,731	-101,128	0.377	-38,153
TransAlta Energy Marketing	Market	447,332	-1,097,517	-650,185	0.377	-245,297
TransCanada Energy Sales Ltd	Market	176	-9,679	-9,503	0.377	-3,585
Turlock Irrigation District	Market	988	0	988	0.437	431.8
Vitol Inc.	Market	33,504	-44,959	-11,455	0.377	-4,322

Columbia River Energy Supply Contracts

During 2024, approximately 14.8 percent of PSE's energy supply requirement was obtained through long-term contracts with three Washington Public Utility Districts (PUDs) that own and operate hydroelectric projects on the Columbia River (Mid-Columbia). PSE's portion of the power output of the PUD projects is shown in Table 4.

Table 4. Columbia River Electric Energy Supply Contracts

Project	Contract Expiration	Percent of Output (PSE Share)	MW Capacity (PSE Share, approx.)
Rock Island Project (Chelan County PUD)	2031	25%	156
Rocky Reach Project (Chelan County PUD)	2031	25%	325
Wells Project (Douglas County PUD)	2028	27.1%	228
Priest Rapids Development (Grant County PUD)	2052	0.6%	6
Wanapum Development (Grant County PUD)	2052	0.6%	7

2024 Carbon Dioxide Emissions - Results & Discussion

Overall, PSE's CO_2e emissions intensity from total electricity delivered to customers decreased from 877.5 lb/MWh in 2023 to 830.3 lb/MWh in 2024 (as seen in Table 6). As shown in Table 5, in 2024, 65.9 percent of electricity delivered to PSE customers was generated by the company, 34.1 percent of electricity was purchased via firm contracts (49.0 percent) and non-firm contracts, i.e., spot market (-14.9 percent)[5]. Of the CO_2e emissions associated with electric delivery, 75.9 percent were from electricity generated by PSE, and 24.1 percent were from purchased electricity (39.1 percent via firm contracts and -15.1 percent via non-firm contracts).

It is important to remember that CO_2e emissions vary based on the fuel source or technology used to generate the electricity. Some sources are more emissions intense than others. "Intensity" is the relationship between emissions and production, and utilities can measure that intensity using a metric called pounds of CO_2e per megawatt-hour (lb/MWh) of electricity produced. For instance, in 2024 (as seen in Table 5), about 15.0 percent of the electricity generated by PSE came from coal combustion, but this fuel source represented about 35.1 percent of the CO_2e emissions from electricity generated by PSE. Natural gas accounted for 65.9 percent of the electricity generated by PSE; however, this fuel source represented 64.9 percent of the CO_2e emissions from electricity generated by PSE. Renewable energy accounted for 19.1 percent of the electricity generated by PSE-owned generation resources and produced zero CO_2e emissions.

Compared to 2023 (as seen in Table 7), total electricity delivered to customers in 2024 decreased slightly, by 0.3 percent, and total emissions decreased slightly, by 5.7 percent. This trend is due primarily to a decrease in PSE coal generation and purchases. Coal generation decreased significantly, by 18.4% in 2024 compared to 2023, which resulted in 1.1 MM metric tons of fewer emissions compared to the previous year.

5 This is net of all unspecified purchases.

Table 5. Summary of Total Energy Delivered (MWh) and Total Emissions (metric ton CO_2e)

2024	Total Energy Delivered (MWh)				Total Emissions (CO_2e)			
Source	MWh Total	MWh % of PSE All-owned Total	MWh % of PSE Thermal Only	MWh % of Total	Metric Ton Total	Metric Ton % of PSE All-owned Total	Metric Ton % of PSE Thermal Only	Metric Ton % of Total
PSE Owned Coal	2,195,159	15.0%	18.5%	9.9%	2,230,496	35.1%	35.1%	26.7%
PSE Owned Gas	9,649,521	65.9%	81.5%	43.4%	4,119,051	64.9%	64.9%	49.2%
PSE Owned Renewable	2,789,666	19.1%		12.6%	0	0.0%		0.0%
Firm Coal	2,700,452			12.2%	3,015,251			36.0%
Firm All Other	8,173,971			36.8%	258,970			3.1%
Unspecified	-3,299,563			-14.9%	-1,259,530			-15.1%
Total (from energy)	22,209,206				8,364,238			
PSE Own plus Firm PPA	25,508,769				9,623,768			
Total PSE Only	14,634,346			65.9%	6,349,547			75.9%
Total Firm Only	10,874,423			49.0%	3,274,221			39.1%
Total Unspecified Only	-3,299,563			-14.9%	-1,259,530			-15.1%

Table 6. 2023 and 2024 Total Energy Delivered (MWh), Total Emissions (metric ton CO_2e), and Emission Intensity (lb/MWh)

	2024					*2023*				
	Energy MWh	%	Emissions Metric Ton	%	Intensity (lb/MWh)	Energy MWh	%	Emissions Metric Ton	%	Intensity (lb/MWh)
PSE Owned Coal	2,195,159	9.9%	2,230,496	26.7%	2,240.1	3,326,355	15%	2,741,750	31%	1,817.2
Firm Coal	2,700,452	12.2%	3,015,251	36.0%	2,461.6	2,673,671	12%	3,536,340	40%	2,916.0
PSE Owned Gas	9,649,521	43.4%	4,119,051	49.2%	941.1	9,954,456	45%	4,578,487	52%	1,014.0
PSE Owned All Other	2,789,666	12.6%	0	0.0%	0.0	2,265,369	10%	0	0%	0.0
Firm All Other	8,173,971	36.8%	258,970	3.1%	69.8	8,794,954	39%	113,329	1%	28.4
Unspecified	-3,299,563	-14.9%	-1,259,530	-15.1%	841.6	-4,732,543	-21%	-2,100,695	-24%	978.6
PSE Owned Plus Firm PPA	25,508,769		9,623,768		831.7	27,014,805		10,969,906		895.2
PSE Owned	14,634,346	65.9%	6,349,547	75.9%	956.5	15,546,180	69.8%	7,320,237	82.5%	1,038.1
Firm	10,874,423	48.96%	3,274,221	39.1%	663.8	11,468,625	51.5%	3,649,669	41.1%	701.6
Unspecified	-3,299,563	-14.86%	-1,259,530	-15.1%	841.6	-4,732,543	-21.2%	-2,100,695	-23.7%	978.6
Total (Own, Firm, Unspecified)	22,209,206		8,364,238		830.3	22,282,262		8,869,210		877.5

Table 7. Comparison to Previous Year: Total Energy Delivered (MWh), Total Emissions (metric ton CO_2e), and Emission Intensity (lb/MWh)

	2024 vs. 2023				
	Energy MWh	%	Emissions Metric Ton	%	Intensity (lb/MWh)
PSE Owned Coal	-1,131,196	-34.0%	-511,254	-18.6%	423.0
Firm Coal	26,781	1.0%	-521,088	-14.7%	-454.3
PSE Owned Gas	-304,935	-3.1%	-459,436	-10.0%	-72.9
PSE Owned All Other	524,296	23.1%	0	0.0%	0.0
Firm All Other	-620,983	-7.1%	145,641	0.0%	41.4
Unspecified	1,432,980	-30.3%	841,165	-40.0%	-137.0
PSE Owned	-911,834	-5.9%	-970,690	-13.3%	-81.6
Firm	-594,202	-5.2%	-375,447	-10.3%	-37.8
Unspecified	1,432,980	-30.3%	841,165	-40.0%	-137.0
Total (Own, Firm Unspecified)	-73,056	-0.3%	-504,972	-5.7%	-47.2

Trends Discussion

The relative amount of GHG emissions from the electricity sources did not align with the amount of power produced from each electricity source. This trend is due to factors related to the intensity of emissions from each source, which reflects the relationship between CO_2e and power production of each source.

For example, about 15.0 percent of the electricity generated by PSE came from coal combustion, which has a high CO_2e emission intensity compared to natural gas and oil combustion sources. Of CO_2e emissions from electricity generated by PSE (direct emissions), about 35.1 percent were from coal-combustion generation. The high CO_2e emission intensity of coal-combustion generation made the overall CO_2e emission intensity of PSE's electric operations high.

Another example highlighting this trend occurs in purchased electricity. Roughly 74.3 percent[6] of firm contract electricity purchased by PSE came from renewable plants in the Pacific Northwest (primarily hydroelectric), while the remaining purchases were sourced from thermal plants. Since hydroelectric generation is considered a non-GHG emitting source, almost all of the CO_2e emissions generated from firm contract purchased electricity come from coal and natural gas generated electric operations.

A third example relates to how emissions are calculated for electricity purchased by PSE on the spot market (i.e., non-firm contracted electricity purchases). Again, these purchases are sourced from different utilities and non-utilities via the "grid" system of electric distribution, making the source of energy challenging to track and measure. Therefore, regional average emission factors were used to estimate non-firm contract purchased electricity. For instance, electricity purchased by a utility from an energy trader could have been purchased by the energy trader from a hydroelectric facility near the utility's operational territory or from a second utility generating electricity using coal outside the utility's operational territory. The emissions associated with the generation are not known because they could be significantly different for each source. Therefore, the emissions associated with non-firm contract purchased electricity were calculated using the unspecified emission rate factor provided by Ecology that generally reflects the suite of generation sources that produced the purchased electricity.

[6] Calculated, Attachment A (Known Resources)

Centralia Coal Transition Power

It is important to distinguish between emissions from PSE's owned thermal resources above and the contract PSE signed with TransAlta for coal transition power from the Centralia power station ("Centralia"). In this report, PSE incorporates a breakdown of energy and emissions from Centralia and differentiates Centralia generation and Centralia supply, which is power purchased by the owner of Centralia (i.e., TransAlta), and supplied to PSE. PSE's report will apply different emissions factors for energy supplied versus generated from Centralia to reflect known sources of emissions more accurately.

PSE reports the difference between supplied and generated power each year from Centralia in its Annual Report of Energy Delivery to PSE from TransAlta-Centralia Transition Coal in Docket No. UE-121373 ("Coal Transition Report").

PSE's sources of Centralia generation and supply in this report are consistent with its Coal Transition Report.

For power generated from Centralia coal, PSE applied the emission factor following the methodology and data reported to the Environmental Protection Agency (EPA). For power supplied by the Centralia market option, PSE applied the Ecology unspecified rate, 963 lbs per CO_2e/MWh. PSE determined the Ecology unspecified rate was reasonable because it provides consistency given the uncertainty of sources purchased by TransAlta from other Balancing Authority Areas. PSE plans to use this same methodology to differentiate Centralia generation and supply in this report for the Centralia coal transition contract duration.

Population Data

PSE tracks customers served by class of service but does not track the number of people (population) served. Therefore, population data in this report is estimated based upon methodology agreed to by PSE, UTC Staff, and the other utilities.

The total service area population was estimated by multiplying the total residential customers in PSE's service area by the average household size (AHS) of occupied homes, using data from the most recent five-year estimates from the U.S. Census Bureau's American Community Survey (ACS).

For more detailed information, see Appendix 1: Estimation of PSE Service Territory Population.

Unspecified Market Purchases

This report includes energy that PSE has purchased from the spot market associated with the corresponding generation year where the actual generating unit is unknown (unspecified). As stipulated in this rule, PSE uses an unspecified emissions rate for these spot market purchases where the energy source is unknown (WAC 480-109-300(4))[7]. The net system mix emissions rates for PSE and the other utilities during the reporting period have been calculated and provided by Ecology.

[7] Bonneville Power Administration (BPA) Asset-Controlling Supplier (ACS) System emission factors are used for BPA specified purchase claims beginning in reporting year 2022 (https://apps.ecology.wa.gov/publications/documents/2302002.pdf). For all other unspecified electricity purchases, the default emission factor provided by the Washington State Department of Ecology is used (RCW 19.405.070).

Section 4. Appendices

Appendix 1: Estimation of PSE Service Territory Population

This appendix documents how PSE estimated the population within its service territory to meet the reporting requirement of WAC 480-109-300(2)(c): Megawatt-hours per capita. The estimated population for each reporting year is the product of PSE residential customer count for the year multiplied by the weighted average household size of the counties that PSE provides electric service. The methodology is consistent with the preferred Per Capita Methodology described in the UTC Staff's final report[8] and the Commission's Final Order[9] on the estimation of population in an electric utility service territory. As prescribed in the Commission's Final Order paragraph 17, "To produce the reports required by WAC 480-109-300(2)(c), the utilities should use the methodology agreed upon by stakeholders and described in the final report and this order." [10]

PSE's customer information system is the ultimate source of the annual residential customer count data, which represents the number of households within PSE service territory. These customer count data are as reported in PSE's FERC financial reporting Form No. 1: Annual Report of Major Electric Utilities, Licensees, and Others. Not all residents in a multi-family or mixed-use commercial and residential building are included in PSE's residential customer count at this time. PSE does not have reliable data to make a separate adjustment to account for the persons residing in master-metered residential buildings.

The average household size used in PSE's WAC 480-109-300: Energy and emissions intensity metrics is 2.48. This number is the overall average of persons per household for PSE's service territory weighted by the population size for each county.

The source of the five-year average of county-level data is the United States Census Bureau's American Communities Survey, which can be accessed using the Bureau's web-based application QuickFacts at www.census.gov/quickfacts/table/PST045215/00.

The following table details the data and the calculation of the 2.48 persons average household size that used in the determination of PSE service territory population for megawatt hours per capita (WAC 480-109-300(3)(c)).

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[8] UE-131732 Proposed EE Metrics Workgroup Results – Final Report, August 7, 2015, (Report at2-3).

[9] UE-131732, Final Order, General Order R-581: Order Adopting Rule Permanently, September, 10, 2015, (Order at 6 §17).

[10] UE-131732, Final Order, General Order R-581: Order Adopting Rule Permanently, September, 10, 2015, (Order at 6 §17).

2016-2020 Census Bureau, Updated July 2021			
County	Population	Per House	Total
Skagit	130,696	2.55	333,275
Pierce	925,708	2.64	2,443,869
Island	87,432	2.31	201,968
King	2,252,305	2.43	5,473,101
Kitsap	274,314	2.46	674,812
Kittitas	45,499	2.32	105,558
Thurston	297,977	2.5	744,943
Whatcom	228,831	2.47	565,213
		Weighted Average	2.48

Appendix 2: Emissions Reporting Methodology

1. Owned Thermal Resources

PSE wholly owns three dual-fuel combustion turbine generation facilities (Frederickson, Fredonia, and Whitehorn), five natural gas combined cycle generation facilities (Encogen, Goldendale, Mint Farm, Ferndale and Sumas), and one internal diesel combustion generation facility (Crystal Mountain). Also, PSE partially owns one coal-combustion generation facility (Colstrip) and one natural gas combined cycle generation facility (Freddy 1).

PSE's CO_2e emissions from electric operations are calculated using the EPA GHG Mandatory Reporting Rule Subparts C and D (Tiers 2 & 4) calculation methodologies. Utilizing Subparts C & D, carbon dioxide mass is calculated based on the amount of fuel consumed by each generation facility.

Thermal facilities utilizing the Subpart C method include Frederickson, Fredonia Units 1 & 2 and Whitehorn. Annual CO_2e mass emissions using Subpart C are calculated with these plant measurements: 1) fuel heat content (HHV), 2) the amount of fuel burned (volume)[11] and, 3) a default specific emission factor (EF). An example calculation is provided below.

Example = Volume gas x fuel heat content HHV x EF =

(334,172,000 scf natural gas measured) x (0.0010920 MMBtu/scf measured) x
(53.06 kg CO_2/MMBtu) = 21,343 short ton CO_2

Thermal facilities utilizing the Subpart D method include Encogen, Goldendale, Mint Farm, Ferndale, Sumas, Fredonia Units 3 & 4, Freddy 1 and Colstrip. This method utilizes direct continuous emissions measurement systems (CEMS) as prescribed in Part 75 of the EPA Acid Rain Program. Stack gas and flow measurements are measured continuously, and this data is used in prescribed equations (via the CEMS system) to determine total GHG mass. Part 75 also includes certification and Quality Assurance (QA)/Quality Control (QC) requirements to ensure that data validity is confirmed at the beginning of a monitoring program.

2. Firm Contract Purchases

PSE calculated firm contract purchased emissions using the Ecology methodology outlined in WAC 177-444-040(2).

- Step 1: Obtain plant GHG emissions. GHG emissions for this method are defined as the sum of all Subpart C and Subpart D emissions from the individual power plant as

[11] Measured in standard cubic feet (scf).

published by EPA based on 40 CFR[12] Part 98 reporting consistent with the methods adopted in WAC 173-441-120. Emissions are on a calendar year basis and in units of metric tons CO_2e. Use emissions values specific to the calendar year in the calculation.

- Step 2: Obtain plant net electric generation. Net electric generation is the sum of all annual net generation (MWh) from Form EIA-923 for the power plant for the calendar year for all reported fuel type codes.
- Step 3: Calculate transmission losses using the following method as directed by the regulatory agency. Transmission losses are zero MWh if utility claims are reported on a plant net output basis, like utility claims measured at the Busbar.
- Step 4: Obtain cogeneration correction factor. Account for nonelectric heat use at the power plant by dividing the sum of annual electric fuel consumption (MMBtu) by the sum of annual total fuel consumption MMBtu from Form EIA-923.
- Step 5, Firm Contract Plant Emission Rate Equation (Ecology Method) =

$$\frac{\text{EPA plant GHG emissions} \times \text{cogeneration correction factor}}{\text{plant net electric generation}} \times (\text{utility claims} + \text{transmission losses})$$

3. Non-Firm Contract Purchases

PSE's emissions from non-firm contract purchased electricity were estimated using the net-by-counterparty methodology for purchases and sales of non-firm contract purchased electricity pursuant to the Staff directive described below:

" 3. Unknown Sources – Purchase and sales reporting methodology: After several rounds of discussion last year and after reviewing analysis performed by the utilities, Staff believes the appropriate methodology for reporting purchases and sales is the net-by-counterparty approach:
(a) for each transaction partner whose generation is from an unknown resource, subtract the total annual sales to this party from the total annual purchases from this party;
(b) if the result is positive, apply the Ecology unspecified intensity factor to calculate emissions associated with the net purchase;
(c) if the result is negative, apply an aggregate, fleet-wide emissions intensity factor for the utility's known sources to calculate emissions associated with the net sale.
Staff understands that this approach has largely been implemented by PSE in prior reports. Staff contends that the net-by-counterparty approach represents an optimal

12 CFR stands for Code of Federal Regulations.

balance among the three competing priorities of accuracy, consistency, and burden on company and commission resources."[13]

4. Non-Firm Purchases in the Energy Imbalance Market (EIM)

    1. For non-PSE units:
        - Apply net-by-counterparty calculus described in 3) above

    2. For PSE units:
        - If end-of-year net (by plant) is greater than zero, then PSE was a net purchaser (from the California Independent System Operator, CAISO); assign Commerce rate. If end-of-year net (by plant) is less than zero, then PSE had excess generation.
        - For excess generation from PSE units, will assign "zero" emission rate because emissions are accounted for under "Generation" (to avoid double counting).

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[13] UE-170696. *PSE 2007-2016 EEI report Staff Compliance Letter* (June 26, 2018). Staff compliance letter recommending that the Commission acknowledge Puget Sound Energy's compliance with WAC 480-109-300. ATTACHMENT Staff feedback re: PSE's 2007-2016 EEI Report, page 1 of 2.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-57:
Wash. Utils. Comm'n Rejection of Colstrip Investments in Puget Rates

Service Date: December 19, 2025

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY Respondent.	DOCKET UE-240729 FINAL ORDER 05 REJECTING TARIFF SHEETS; AUTHORIZING AND REQUIRING COMPLIANCE FILING

Synopsis: *The Washington Utilities and Transportation Commission rejects the tariff sheets field by Puget Sound Energy (PSE or the Company) filed on September 30, 2024, and allowed to provisionally go into effect subject to refund. The Commission has considered the full record and requires PSE to file tariff sheets that will result in a decrease in revenue of approximately $6,843,705 or 0.08 percent in accordance with the decisions in this Order summarized below, subject to the true-up required by this Order. The Commission concludes that Colstrip Units 3 and 4 will be "retired" within the meaning of CETA when PSE transfers its ownership in those units to NorthWestern Energy Corporation (NorthWestern) on January 1, 2026. The Commission further determines that the Abandonment and Acquisition Agreement (A&A Agreement) is not subject to Commission approval because Colstrip is not useful or necessary for PSE's service in Washington at the time of transfer. However, the Commission establishes a condition to facilitate review of future property transfers to comply with CETA. The Commission determines that PSE's Colstrip investments are not used and useful after December 31, 2025, and that such investments should be prorated, with the exception of six investments in support of human health and safety. The Commission further requires PSE to establish the in-service dates of two other investments, the U4 Generator Exciter and the Northern Cheyenne AAQ System, to establish the prorated level of recovery, if any. The Commission determines that PSE has demonstrated that the prorated portion of its Colstrip investments are prudent, other than its investment in the TOFA SmartBurn component and four projects that lack a capital justification. The Commission further finds that the annual amortization amount associated with the 2024 Colstrip outage should be adjusted to $1,603,174. The Commission finds that PSE should be required to refund over-collected amounts in the manner described in this Order. The Commission further requires PSE to file an accounting of its 2025 Colstrip investments as part of its Sch. 141COL annual filing,*

consistent with the decisions in this Order, to allow for review of its 2025 Colstrip investments.

TABLE OF CONTENTS

PROCEDURAL HISTORY

1 On September 30, 2024, Puget Sound Energy (PSE or Company) filed with the Washington Utilities and Transportation Commission (Commission) a proposed revision to rates under the established Colstrip Adjustment Rider Schedule 141COL. PSE requested an annual revenue increase of $4.1 million, or 0.14 percent, which for the typical residential customer using 800 kWh per month would be a rate increase of $.18 or 0.16 percent.

2 On December 19, 2024, this matter came before the Commission at the Open Meeting. Commission staff (Staff) raised concerns about a number of capital investments reflected in the filing that are potentially unrecoverable by law or imprudent for Washington ratepayers. The Commission entered Order 01 Complaint and Order Allowing Rates Subject to Later Review and Refund; Setting Matter for Adjudication (Order 01) in this docket, requiring PSE to file revised tariff pages no later than December 23, 2024, with an effective date of January 1, 2025, indicating that the increased rates would go into effect on January 1, 2025, subject to refund.[1] The Company was directed by Order 01 to file revised tariff pages, which the Company complied with on December 20, 2024.

[1] On December 23, 2024, the Commission issued an errata to Order 01 and a revised Order 01. The revision did not affect the substantive terms or determinations in Order 01.

3 On February 27, 2025, Alliance of Western Energy Consumers (AWEC) filed its Petition to Intervene, arguing that it has a substantial interest in this proceeding based on its participation in the establishment of the Colstrip Adjustment Rider Schedule and the impacts of proposed rate increases on AWEC members who purchase power from PSE.[2]

4 On March 6, 2025, NW Energy Coalition (NWEC) filed its Petition to Intervene arguing that it has a substantial interest in this proceeding based upon its historic and ongoing work with utility companies to promote a clean, reliable, affordable, and equitable energy future.

5 On March 12, 2025, the Commission convened a virtual prehearing conference before Administrative Law Judges (ALJ) Harry Fukano and Jessica Kruszewski. At the hearing the presiding ALJ granted AWEC and NWEC's unopposed petitions to intervene in this matter.

6 On March 26, 2025, the Commission entered Order 03, Prehearing Conference Order and Notice of Hybrid Evidentiary Hearing (Order 03), which set an evidentiary hearing for September 3, 2025, at 9:30 a.m.

7 On April 4, 2025, the Commission issued a Notice of Revised Procedural Schedule at the request of PSE to revise the date of the initial settlement conference to April 16, 2025, and for PSE's initial testimony to be due on April 22, 2025. No party opposed PSE's request to modify the procedural schedule.

8 On August 28, 2025, the Commission held a combined virtual public comment hearing in Dockets UE-240729 and UG-240884. Eight participants voiced opposition to PSE's requests for cost recovery in this docket.[3]

9 In addition to the virtual public comments, the Commission and Public Counsel received a total of forty-six written comments with forty opposed, two in favor, and four undecided. Of these commenters, many PSE customers raised concerns about increases in rates while living on a fixed income.[4]

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[2] *WUTC v. Puget Sound Energy*, Dockets UE-220066 & UG-220067 (*consolidated*), and Docket UG-210918 Order 24/10 (Dec. 22, 2022).

[3] *WUTC v. Puget Sound Energy*, Docket UE-240729, Virtual Public Comment Hearing Recording (Aug. 29, 2025).

[4] *WUTC v. Puget Sound Energy*, Docket UE-240729, Comment Matrix Attachment A (Sept. 17, 2025).

10 On September 3, 2025, the Commission convened a hybrid evidentiary hearing before the Commissioners that was presided over by ALJ's Harry Fukano and Jessica Kruszewski.

11 On September 5, 2025, the Commission issued Notice of Bench Requests (BR) 1-4 requesting additional information from the parties with a deadline for responses to BR 1-3 set for September 10, 2025, at 5:00 p.m., and set a deadline for replies from non-company parties to the company's response to BR 1 for September 17, 2025. The deadline for responses to BR 4 was set for September 17, 2025. The Company submitted supplemental responses to BRs 3 and 4 on October 2, 2025.

12 On October 10, 2025, the Commission issued a Notice requesting supplemental briefing from the parties in relation to the interpretation of RCW 19.405.020 to aid the Commission in its decision-making with a deadline for set for October 24, 2025, at 5:00 p.m.

13 On October 21, 2025, the Commission issued BR 5-6 asking the Company to clarify additional questions it had in relation to the Company's investment into SmartBurn and its NOx control system.

14 **PARTY REPRESENTATIVES.** Donna L. Barnett of Perkins, Coie LLP, represents PSE. Nash Callaghan and Josephine Strauss, Assistant Attorneys General, represent Staff.[5] Tad Robinson O'Neill, Jessica Johanson-Kubin, and Robert Sykes, Assistant Attorneys General, represent the Public Counsel Unit of the Attorney General's Office (Public Counsel). Sommer Moser and Michelle Madsen of Pepple Moser, P.C., represent AWEC. Yochanan Zakai and Orran Balagopalan of Shute, Mihaly & Weinberger, represent NWEC.

BACKGROUND

15 **Clean Energy Transformation Act (CETA).** In 2019, the Washington State Legislature passed the Clean Energy Transformation Act (CETA),[6] codified in chapter 19.405 of the Revised Code of Washington (RCW). In the face of immediate and significant threats posed by climate change, CETA requires that each Washington electric utility "eliminate coal-fired resources from its allocation of electricity" no later than December 31, 2025,[7] that all retail sales of electricity are "one hundred percent carbon-neutral by January 1,

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

[6] Laws of 2019, ch. 288, §§ 1–13 and 26. Codified as chapter 19.405 RCW.

[7] RCW 19.405.030(1). *See also* RCW 19.405.020(1)

2030,"[8] and that by January 1, 2045 "one hundred percent of all sales of electricity to Washington retail customers" are supplied by either non-emitting or renewable electricity generation resources.[9] CETA promotes a transition to a clean energy economy,[10] provides incentives for clean alternative energy sources,[11] and expands the meaning of "public interest" under Title 80 RCW.[12] However, CETA's requirement for each utility to eliminate coal-fired resources from its allocation of electricity "does not include costs associated with decommissioning and remediation of these facilities" provided the Commission deems these costs to be prudently incurred.[13]

16 **Colstrip, Ownership and Operations Agreement (O&O Agreement), and Development of the Abandonment and Acquisition Agreement (A&A Agreement).** This case concerns the recovery of PSE's portion of investments in the Colstrip Steam Electric Station (Colstrip). Colstrip was a four-unit coal-fired electric generation facility operated by Talen MT (Talen) and located in Colstrip, Montana.[14] Colstrip Units 1 and 2 were closed in January 2020.[15] At present, PSE owns 25 percent of the remaining Colstrip Units 3 and 4, with the other 75 percent divided among other entities as follows:[16]

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

[8] RCW 19.405.010(2); RCW 19.405.040(1).

[9] RCW 19.405.010(2); RCW 19.405.050(1).

[10] RCW 19.405.010(1).

[11] RCW 19.405.010(4).

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

[13] RCW 19.405.030(1)(a)-(b).

[14] Atwood, Exh. NLA-1T at 2:9, 7:3-4, 8:19.

[15] Atwood, Exh. NLA-1T at 7:3-4, 12-13.

[16] Atwood, Exh. NLA-1T at 7:3-9.

17 The owners of Colstrip Units 3 and 4 operate under the terms of the Common Facilities Agreement which describes ownership interests, among other things.[17] Contracts relating to Colstrip Units 1 and 2 expired when the units were closed.[18] Additionally, the owners of Colstrip Units 3 and 4 operate under the O&O Agreement, which was entered into in 1981 and continues to govern the operation of the Colstrip units.[19] Under the O&O Agreement, PSE must fund costs to operate and maintain Colstrip Units 3 and 4 as long as the Company holds any ownership shares. [20] This includes requiring each owner to provide the plant with enough coal to generate the owner's share of the plant's minimum operating capacity.[21] Each year, the owners of the Colstrip units must approve a budget, but because PSE holds 25% ownership, it is not the sole entity approving or denying a budget with a minority vote.[22]

18 To comply with CETA's mandate to have coal-fired generation removed from its allocation of electricity by December 31, 2025, PSE has made several prior attempts to sell or dispose of Colstrip Units 3 and 4. PSE first entered into an agreement with NorthWestern in 2019 to sell Colstrip Units 3 and 4 with a purchase price and an exchange of rights on the Colstrip transmission system, but withdrew the agreement after pushback.[23] In a second attempt, in 2022, PSE and Talen worked out an abandonment agreement but the transfer did not occur as Talen went through a bankruptcy in 2024.[24] Talen did not get approval of the PSE abandonment agreement in the bankruptcy, so the agreement was invalidated.[25] PSE then entered into the A&A Agreement with NorthWestern to transfer its interest in Colstrip Units 3 and 4.[26] PSE entered into this agreement without seeking Commission approval.[27] The transfer will occur at 12:00 a.m. on January 1, 2026, Pacific Standard Time.[28]

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[17] Atwood, Exh. NLA-1T at 7:12-13.

[18] Atwood, Exh. NLA-1T at 7:12-14.

[19] Atwood, Exh. NLA-1T at 7:16-18; Atwood, Exh. NLA-4.

[20] Atwood, Exh. NLA-1T at 8:3-4.

[21] Atwood, Exh. NLA-1T at 8:3-7.

[22] Atwood, Exh. NLA-1T at 9:14-20, 16:12-21.

[23] TR Roberts at 94:20-25, 95:1-8; Atwood, Exh. NLA-1T at 19:8-10.

[24] TR Roberts at 95:9-20; Atwood, Exh. NLA-1T at 19:11-22.

[25] Atwood, Exh. NLA-1T at 19:11-22.

[26] Atwood, Exh. NLA-1T at 19:6-22.

[27] Mullins Exh. BGM-1T at 2:10-16.

[28] PSE's Response to BR 3.

I. Applicable Law

19 The Legislature has entrusted the Commission with broad discretion to regulate and set rates in the public interest[29] that are just, fair, reasonable and sufficient,[30] and to balance the needs of the public to have safe, reliable, and appropriately priced services, while also assuring that the utilities earn enough to remain in business.[31] The Commission has previously interpreted the fair, just, reasonable, and sufficient standard to mean that "rates that are *fair* to customers and to the Company's owners; *just* in the sense of being based solely on the record developed in a rate proceeding; *reasonable* in light of the range of possible outcomes supported by the evidence; and *sufficient* to meet the needs of the Company to cover its expenses and attract necessary capital on reasonable terms."[32]

20 However, if after hearing the Commission finds that the rates charged by the utility are:

> . . . unjust, unreasonable, unjustly discriminatory or unduly preferential, or in any wise in violation of the provisions of the law, or that such rates or charges are insufficient to yield a reasonable compensation for the service rendered, the commission shall determine the just, reasonable, or sufficient rates, charges, regulations, practices or contracts to be thereafter observed and in force, and shall fix the same by order.[33]

21 For proposed rates, as in this case, the Commission may enter an order under this same standard as if the proposed rates were already effective.[34]

22 As a general matter, the burden of proving that a proposed increase is just and reasonable is upon the public service company,[35] and the burden of proving that the presently effective rates are unreasonable rests upon any party challenging those rates.[36]

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[29] RCW 80.01.040(3).

[30] RCW 80.28.010.

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

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

[33] RCW 80.28.020.

[34] RCW 80.04.130(1).

[35] *Id*.

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

23 As discussed above, in 2019, the Legislature expanded the traditional definition of the public interest standard. As Washington state transitions to a clean energy economy, the Legislature provided that the public interest includes: “The equitable distribution of energy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health, economic, and environmental benefits and the reduction of costs and risks; and energy security and resiliency.”[37] In achieving these policies, “there should not be an increase in environmental health impacts to highly impacted communities.”[38]

24 Following the passage of RCW 80.28.425, which requires utilities to file multi-year rate plans when filing a general rate case (GRC), the Commission indicated its commitment to considering equity while regulating in the public interest: “So that the Commission’s decisions do not continue to contribute to ongoing systemic harms, we must apply an equity lens in all public interest considerations going forward.”[39] The Commission also explained that regulated companies should be prepared to address equity considerations in future cases: “Recognizing that no action is equity-neutral, regulated companies should inquire whether each proposed modification to their rates, practices, or operations corrects or perpetuates inequities.”[40]

II. Application of RCW 19.405.030 - Interpretation of “*Retirement*”

25 CETA requires the following:

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

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[37] RCW 19.405.010(6).

[38] RCW 19.405.010(6).

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

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

26 The Company has argued that a transfer of its ownership rights in Colstrip Units 3 and 4 is a retirement under RCW 19.405.030(3) and is the type of transfer the Legislature had in mind when the statute was drafted.[41] PSE argues that it has done exactly what the statute intended and because the "long-lived plant will be retired by PSE upon transfer of ownership . . . the Commission must allow the cost to invest in that plant to be recovered either directly or indirectly in rates, as the law requires."[42] PSE alleges that this treatment applies to 2024 and 2025 plant additions, which will become unrecovered plant as of December 2025.[43]

27 NWEC argues that the Commission should apply the dictionary definition of "retirement" so that in the context of this case, retirement would mean that Colstrip ceases to produce electricity. To support its contention that the Company interprets "retirement" similarly to NWEC, NWEC points to PSE's Colstrip FACTS Frequently Asked Questions webpage, in which PSE states that "there are no plans to retire Colstrip Units 3 & 4" and that only Units 1 and 2 have been.[44] Further, NWEC contends that RCW 19.405.030(3) does not apply to PSE's investments in Colstrip Units 3 and 4 because the statute intended a "financial assurance" that if a company retires a fossil fuel generating resource, as in the resource is no longer working and causing pollution, shareholders would not be asked to write off undepreciated investment.[45] Specifically, NWEC takes the position that CETA intended to incentivize companies to retire fossil fuel plants and that it does not apply to investments that extend the life of the plant beyond 2025.[46] NWEC supports this assertion by noting that "those financial incentives were carefully written in the past tense, so that they only apply after the plant 'has been retired from service.'"[47] Because Colstrip Units 3 and 4 will continue to operate beyond 2025, NWEC argues that they will not be retired as intended by CETA, so RCW 19.405.030(3) does not apply to this proceeding.[48]

28 In applying the language of RCW 19.405.030(3)(a), NWEC contends that "termination or expiration of any ownership" does not independently constitute retirement and that the

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[41] Steuerwalt, Exh. MS-1T at 8:13-16.

[42] Steuerwalt, Exh. MS-1T at 8:13-19.

[43] Steuerwalt, Exh. MS-1T at 8:19-20, 9:1-2.

[44] McCloy, Exh. LCM-1T at 6:6-8.

[45] McCloy, Exh. LCM-1T at 6:11-14.

[46] McCloy, Exh. LCM-1T at 6:14-21.

[47] McCloy, Exh. LCM-1T at 6:20-21, 7:1.

[48] McCloy, Exh. LCM-1T at 7:1-6.

statute lists causes of retirement and does not "define or alter the plain meaning of the word retired."[49] Similarly, NWEC alleges that section (3)(b) of the statute that allows "such treatment if the retirement of the facility is in the public interest[]" does not apply because Colstrip Units 3 and 4 have not been retired, but even if they had, life extending investments are not prudent nor in the public interest [50]

29 Additionally, NWEC argues that CETA requires electric utilities to "eliminate coal-fired resources from their 'allocation of electricity' by December 31, 2025," but "makes an explicit exception for decommissioning and remediation costs."[51] NWEC interprets this to mean that "CETA did not authorize the recovery of undepreciated investment in fossil resources that remain in-service beyond December 31, 2025."[52]

30 Public Counsel takes a similar position to NWEC and argues that Colstrip Units 3 and 4 will not be retired as intended by RCW 19.405.030(3) after December 31, 2025.[53] Further, Public Counsel alleges that RCW 19.405.030(3) does not apply to this proceeding and the Commission should construe the word "retire" according to its plain language meaning, in which case there are no identifiable retirement dates for Colstrip Units 3 and 4.[54]

31 In response to NWEC's assertion that retirement means "cease to work", PSE asserts that NWEC has misapplied the definition of "retire" and that the "accounting definition of retire related to physical assets that is more relevant here."[55] Specifically, PSE contends that an accounting definition is more appropriate and what was contemplated in the legislation because the statute references "depreciation schedules" which utilize the accounting definition of "retirement."[56] PSE offers two accounting definitions of retirement:

(1) . . . that asset is no longer under the control of that entity . . . [57] , and

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[49] McCloy, Exh. LCM-1T at 7:11-21.

[50] McCloy, Exh. LCM-1T at 8:3-6.

[51] Cebulko, Exh. BTC-1CT at 10:17-20, 11:1-2.

[52] Cebulko, Exh. BTC-1CT at 11:2-6.

[53] Dreyer, Exh. JMD-1CTr at 4:12-18.

[54] Dreyer, Exh. JMD-1CTr at 4:12-16.

[55] Free, Exh. SEF-1T at 2:15-19, 3:1-3.

[56] Free, Exh. SEF-1T at 3:13-17; RCW 19.405.030(2).

[57] Free, Exh. SEF-1T at 4:3-17 (*citing* the master glossary of the Financial Accounting Standards Board's (FASB) Accounting Standards Codification, and Generally Accepted Accounting Principles (GAAP), that defines "retirement" as: "The other-than-temporary removal of a long-lived asset from service. That term encompasses sale, abandonment, recycling, or disposal in some

(2) Retirement of a tangible asset (retirement encompasses its sale, abandonment, recycling or disposal in some other manner) . . .[58]

PSE argues that NWEC's definition of "retire" as "cease to work" is not found within the CETA statute and that NWEC's interpretation "ignores its plain language, and it utilizes a general dictionary definition rather than the specific accounting and regulatory framework that governs utility asset treatment."[59] Further PSE explains that the Financial Accounting Standards Board (FASB) as the authoritative Generally Accepted Accounting Principles (GAAP) source, controls over dictionary definitions in a regulatory context.[60] PSE further asserts that under RCW 19.405.030(3)(a) the term retirement includes "termination or expiration of any ownership"[61] and that the Commission should not be swayed by the restrictions NWEC places on the term retirement as it is used in the statute. [62]

32 The Company argues that CETA intended for coal to be retired from a utility's portfolio with the "financial assurance that shareholders would not be asked to write-off any undepreciated plant investment."[63] The Company asserts that the Legislature expressly included the termination or expiration of ownership to be a cause of retirement and did not include physical cessation of generation as a condition.[64]The Company contends that the central mandate of CETA is to eliminate coal-fired resources from a utility's "'allocation of electricity' by December 31, 2025."[65] To support this contention, the Company asserts that by referencing CETA's use of "depreciation schedules" and "books of account" the Legislature intended for an accounting definition of "retire."[66] The Company also referred to the definition of retirement under Generally Accepted Accounting Principles and by the

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other manner. However, it does not encompass the temporary idling of a long-lived asset. After an entity retires an asset, that asset is no longer under the control of that entity, no longer in existence, or no longer capable of being used in the manner for which the asset was originally acquired, constructed, or developed." https://asc.fasb.org/MasterGlossary).

[58] Free, Exh. SEF-1T at 4:9-17 (*citing* the definition for "retirement" as used by the State of Washington, Office of the Washington State Auditor).

[59] Free, Exh. SEF-1T at 5:1-9.

[60] Free, Exh. SEF-1T at 5:7-9.

[61] Steuerwalt, Exh. MS-1T at 9:18-20; RCW 19.405.030(3)(a)

[62] Steuerwalt, Exh. MS-1T at 9:23-24, 10:1-5.

[63] Brief of PSE at 8 ¶ 17.

[64] Brief of PSE at 8-9 ¶ 18.

[65] Brief of PSE at 9 ¶ 18.

[66] Brief of PSE at 9 ¶ 19.

Washington State Auditor to support CETA's intent for the accounting definition to be used to interpret the term "retire."[67]

33 Public Counsel argues, first, that the Commission should look to the plain language to interpret the word "retirement" in the CETA statute, which is not the accounting definition. Next, Public Counsel emphasizes that the Commission should look to the complete statute and that CETA is concerned with eliminating coal-fired power from Washington's electricity supply and that the primary concern is not depreciation schedules. Using these methods of statutory interpretation, Public Counsel construes "retirement" as used in CETA to mean "end of working life of coal-fired power."[68] The language of RCW 19.405.030(3) allows for recovery of an investment ". . . in a fossil fuel generating resource that has been retired from service . . ." which Public Counsel argues, gives utilities the opportunity to recover on their investments at the time CETA was enacted rather than allowing "companies to accrue millions of dollars of additional life extending costs after CETA was enacted only then to administratively 'retire' the assets on December 31, 2025[.]"[69] Public Counsel stresses that the plain language and spirit of CETA is to provide cost recovery to Washington utilities that close plants, not for transferring assets.[70]

34 In response to the Company's arguments, NWEC asserts "that allowing recovery of undepreciated investment only in fossil resources that *actually cease operations* was 'intended to remove a disincentive for PSE and other Washington owners to retire fossil plants.'"[71] Similar to Public Counsel, NWEC explains that the financial incentives to retire fossil plants were "'carefully written in the past tense' to reflect the Legislature's intention" that recovery of undepreciated investment only occur if the plant "ceased operations."[72]

Commission Determination

35 To understand what the Legislature meant by the word "retire" in CETA, we look to the canons of statutory interpretation. Although NWEC argues that the starting point to interpret a statutory term is to look to its "plain language and ordinary meaning", a technical term should be given its technical meaning rather than its general purpose

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[67] Brief of PSE at 9 ¶ 19; Free, Exh. SEF-1T at 4:3-17.

[68] Brief of Public Counsel at 16 ¶ 50.

[69] Brief of Public Counsel at 16-17 ¶ 52; RCW 19.405.030(3).

[70] Brief of Public Counsel at 16-17 ¶ 52.

[71] Brief of NWEC at 3-4 ¶ 9 (*citing* McCloy, Exh. LCM-1T at 6:14-16).

[72] Brief of NWEC at 3-4 ¶ 9 (*citing* McCloy, Exh. LCM-1T at 6:20-21, 7:1).

dictionary definition.[73] NWEC has provided a narrow scope for defining the term "retire" for the purposes of statutory interpretation and has not considered a technical meaning. In this case, we must also consider "the context of the statute in which that provision is found, related provisions, and the statutory scheme as a whole."[74] Further, we also consider "'all the terms and provisions of the act in relation to the subject of the legislation, the nature of the act, the general object to be accomplished and consequences that would result from construing the particular statute in one way or another.'"[75]

36 Although NWEC has maintained its position that the Commission should apply the dictionary and plain language meaning to the word "retire", NWEC looks to RCW 19.405.010(2) to provide context to the statute. However, RCW 19.405.010(2) refers to transforming Washington's electrical system, which will be accomplished even if Colstrip Units 3 and 4 cease to operate. The Company argues that the statute refers to depreciation schedules to provide context to the intent of the Legislature, and that this is an accounting term. Further, the Company contends that CETA allows for recovery of undepreciated investment when the retirement is caused by the termination or expiration of ownership which demonstrates the Legislature's intent that retirement not be narrowly construed to only mean that the plant is no longer in operation.

37 The Company provided two sources for the accounting definitions for the word "retirement" to guide the Commission in interpreting CETA and identifying whether the Company is able to recover undepreciated investments in Colstrip Units 3 and 4 under RCW 19.405.030(3). Because the statute references depreciation schedules and books of account, the Company has provided the definition used by GAAP, which we find to be a credible source in determining the technical definition of "retire" because it provides the definition as used in regulatory accounting. Further, the Company provides the definition of "retirement" used by the Washington State Auditor's Office, which also considers retirement to be when an asset is no longer controlled by the entity, or controlled by another entity. The Company argues that Colstrip Units 3 and 4 will be retired for PSE under both of these definitions as of January 1, 2026, thus the provisions of RCW 19.405.030(3) apply, and permit the Company to recover its undepreciated investments in Colstrip Units 3 and 4.

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[73] *Tingey v. Haisch,* 159 Wn.2d 652, 658 (2007).

[74] *Taylor v. Burlington N. R.R. Holdings, Inc.*, 193 Wn.2d 611, 614 (2019).

[75] *Burns v. City of Seattle,* 161 Wn.2d 129, 146 (2007) (*citing State v. Krall,* 125 Wn.2d 146, 148 (1994) and *State v. Huntzinger*, 92 Wn.2d 128, 133 (1979)).

38 Because CETA is a relatively new statute without much context and related provisions to help us understand what the Legislature intended with the word “retire”, we also consider the object to be accomplished by CETA, which is, among other things, to remove coal-fired resources from Washington’s electricity supply by the end of 2025, and perhaps more importantly, the impacts of construing the statute one way or another. Public Counsel has argued that CETA intends to provide incentives to utility companies to close coal-fired plants, which Public Counsel argues is demonstrated by the use of past tense, which means the Company cannot recover any undepreciated investments until after the coal-fired plants are no longer operational. Public Counsel further argues that CETA could not have intended for companies to accrue millions of dollars of additional life extending costs after CETA was enacted only to then transfer the plants rather than fully decommission them. However, we have concerns when we look to the reality of the position the Company is placed in if CETA required it to fully decommission Colstrip Units 3 and 4.

39 The Company is required to maintain the plants and fulfill its contractual obligations to other entities. The Company would be faced with the impossible scenario where CETA requires it to not invest in the plants and to not meet its contractual obligations, which could result in a situation where the Company is required to turn to the market to provide power at a much higher cost to customers. The alternative for the Company is to invest in the plant to ensure its safe and reliable operation until it no longer owns its portion of the plant and meet its contractual obligations, but then to absorb the costs to maintain the plants. We are not persuaded that the Legislature intended for electric utility companies to be responsible for the costs to maintain coal-fired plants to provide electricity to Washington customers and then fully decommission coal-fired plants by the end of December 31, 2025.

40 First, we must determine whether the Company can recover undepreciated investments under RCW 19.405.030(3). NWEC and Public Counsel have both argued that because Colstrip Units 3 and 4 will still be operational as of January 1, 2026, the plant will not be retired by the end of December 31, 2025, and the Company cannot recover its undepreciated investment in the plant. The Company has argued that the Legislature intended the accounting definition of “retire” to apply because the statute references depreciation schedules, books of accounts, and sets a condition of retirement to include termination or expiration of ownership. We find this argument persuasive when we look at the context of the statute. We also agree that the Legislature expressly identified termination or expiration of ownership, but did not include language specifically requiring coal-fired plants to no longer be operational, and find this persuasive in demonstrating that the Legislature intended for an accounting definition of the word “retirement.” We do not

agree with NWEC and Public Counsel that the Legislature intended a dictionary definition for the word "retirement" because the statute calls for a technical definition.

41 Next, we consider that the purpose of CETA is to remove coal-fired electricity from Washington's electricity supply by the end of December 31, 2025. That is still accomplished if Colstrip Units 3 and 4 are transferred to NorthWestern and are no longer providing electricity in Washington, even if the plants are not entirely shut down. We have great concern about interpreting RCW 19.405.030(3) to mean the Colstrip Units must cease to operate in order for the Company to recover the investments it made into the plant for which it had a contractual obligation to maintain. If we decide otherwise the Company shareholders would be left having to absorb all of the investments made, which we do not believe was the Legislature's intent. Colstrip Units 3 and 4 are jointly owned so PSE cannot unilaterally choose to "retire" or decommission the plant. Specifically, if the Company had not invested in the maintenance of the plant, the Company would have been in breach of its O&O Agreement with its co-owners and would have had to turn to the market for power, which, based on the evidence presented in this case, likely would have been more costly for PSE's customers than maintenance of the plant.[76] For these reasons, we find it reasonable that the accounting definition should apply in the interpretation of RCW 19.405.030(3). As the Company is under contract to transfer its interest in Colstrip Units 3 and 4 on January 1, 2026, we find that PSE will have retired coal-fired electricity from its electrical supply in Washington and that RCW 19.405.030(3) does not preclude the Company from recovering at least some of the undepreciated investments in Colstrip Units 3 and 4.

III. Asset Transfer

42 PSE entered into the A&A Agreement with NorthWestern on July 30, 2024, to comply with the CETA requirement to no longer include coal-fired power in its allocation of electricity after December 31, 2025. The A&A Agreement transfers PSE's ownership interest in Colstrip Units 3 and 4 by way of abandonment to NorthWestern without a purchase price at 12:00 a.m. on January 1, 2026, Pacific Standard Time.[77] Public Counsel, NWEC, and AWEC raised concerns about the transfer, primarily that the transfer has no purchase price and has not been reviewed or approved by the Commission.[78] Specifically,

[76] Atwood, Exh. NLA-1T at 16:12-21, 17:5-18; Atwood, Exh. NLA-4.

[77] Mullins, Exh. BGM-3 at 19-20; PSE's Response to BR 3.

[78] See Dreyer, Exh. JMD-1CTr at 7:8-22; Cebulko, Exh. BTC-1CT at 5:17-20; Mullins, Exh. BGM-1T at 2:10-20, 3:1-6.

Public Counsel asserts that the investments PSE seeks to recover in this docket may have been covered with a purchase price.[79] NWEC maintains that the Commission should rule on the prudence of the transfer.[80] AWEC argues that NorthWestern should be obligated to pay a fair value because the capital additions will benefit its customers and not PSE customers.[81] AWEC further contends that PSE could have elected to operate its share of Colstrip as a merchant plant.[82]

43 PSE maintains that its decision to enter into the A&A Agreement transferring its ownership share of Colstrip to NorthWestern was reasonable considering the circumstances confronting the Company at the time that it entered into the agreement. PSE states that at the time it signed the A&A Agreement in July 2024, PSE anticipated substantial costs related to bringing Colstrip into compliance with Mercury and Air Toxics Standards (MATS).[83] PSE asserts that the potential MATS compliance costs ultimately caused its planned transfer of Colstrip to the plant operator, Talen to fail.[84] PSE further argues that the Commission should afford little weight to Public Counsel's questioning of PSE witness Roberts regarding an exemption to MATS compliance, based on the lack of documentary evidence in the record regarding the exemption, contending that prudence is concerned with what the utility knew at the time it made a decision.[85]

44 The Company contends that its decision to transfer its Colstrip ownership interest to NorthWestern for no purchase price was reasonable because the potential MATS compliance obligations rendered Colstrip a value-negative asset.[86] PSE also argues that the CETA deadline to remove coal power from the Company's allocation of electricity undermined PSE's bargaining leverage because potential buyers knew that PSE was unable

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[79] Dreyer, Exh. JMD-1CTr at 8:1-4.

[80] Cebulko, Exh. BTC-1CT at 5:17-20.

[81] Mullins, Exh. BGM-1T at 2:10-20, 3:1-6.

[82] Mullins, Exh. BGM-1T at 9:3-21.

[83] Brief of PSE at 24 ¶ 43; Roberts, Exh. RJR-1T at 3:18 – 4:8 (noting July 2024 MATS compliance estimates of $459,000,000 to $594,000,000).

[84] Brief of PSE at 24 ¶ 43; Roberts, TR. at 95:9-20.

[85] Brief of PSE at 24 ¶ 43.

[86] Brief of PSE at 25-26 ¶¶ 44-45; Roberts, Exh. RJR-1T at 4:9-18 (stating "no rational purchaser would ascribe positive value to [Colstrip]" and "[Colstrip]'s fair market value was already demonstrably negative, and any attempt to monetize it would have imposed a greater burden on PSE's Washington ratepayers than an outright abandonment.").

to retain long-term ownership in Colstrip.[87] PSE states that its bargaining power regarding Colstrip was further limited by the Company's need to maintain its Colstrip transmission rights, reducing the number of potential acquirers.[88] Based on these factors, PSE maintains that NorthWestern was the only purchaser who was willing and operationally capable of acquiring PSE's Colstrip ownership interest and that PSE's lack of bargaining power, combined with the need to quickly transfer Colstrip ownership, made a no-value transfer prudent under the circumstances.[89] The Company asserts that no other party has demonstrated that another entity was willing to purchase PSE's Colstrip ownership or identified an appropriate selling price that PSE should have acquired.[90] Furthermore, the Company states that the A&A Agreement is not subject to Commission approval pursuant to RCW 80.12.020 because as of December 31, 2025, Colstrip is not necessary or useful in the performance of any PSE duties to the public.[91]

45 PSE argues that AWEC's proposal that PSE could have retained its ownership interest in Colstrip and operated as a merchant plant would be unreasonably risky for the Company and contrary to Washington clean energy policy. PSE states that while it could have conceivably operated its share of Colstrip as a merchant plant, it would not be able to control dispatch or capital project decisions, which creates a risk that PSE would be forced into uneconomical decisions due to its minority ownership share.[92] PSE contends retaining ownership in Colstrip would have required PSE to participate in a new long term coal fuel contract for the plant, which creates risk that the Company would not be able to recover associated fuel costs.[93] The Company further suggests that its net present value (NPV) analysis demonstrates that the primary risk to Colstrip is an outage event that necessitates the acquisition of power at higher costs, and that merchant plant operation increases this risk.[94] PSE also maintains that it could face potential litigation over an attempt to operate

[87] Brief of PSE at 25-26 ¶ 45; Roberts, Exh. RJR-1T at 4:20 – 5:15.

[88] Brief of PSE at 25-26 ¶ 45; Roberts, Exh. RJR-1T at 6:14 – 7:8. *See also* Roberts, TR. at 94:20 – 95:8 (explaining that the first attempted sale of PSE's Colstrip ownership was withdrawn in part because other parties to the proceeding objected to PSE's proposal to sell part of its Colstrip transmission system rights).

[89] Brief of PSE at 25-26 ¶ 45; Roberts, Exh. RJR-1T at 6:3 – 8:6.

[90] Brief of PSE at 25-26 ¶ 45; Roberts, Exh. RJR-1T at 8:9-18. *See also* Roberts, TR. at 94:20 – 96:22 (explaining that PSE had previously failed to sell or transfer its ownership interest in Colstrip two times prior to entering into the A&A Agreement with NorthWestern).

[91] Roberts, Exh. RJR-1T at 11:3-14.

[92] Brief of PSE at 27 ¶ 48; Roberts, Exh. RJR-1T at 9:3-14.

[93] Brief of PSE at 27 ¶ 48; Roberts, Exh. RJR-1T at 10:4-8.

[94] Brief of PSE at 27 ¶ 48; Atwood, NLA-11T at 14:7-12.

Colstrip as a merchant plant because its incorporation agreements prohibit the Company from creating subsidiaries.[95] PSE states that, even if it were able to operate Colstrip as a non-regulated subsidiary, such operation would either only benefit shareholders or lead to potential cost allocation disputes.[96] Finally, PSE asserts that operating Colstrip as a merchant plant would conflict with the intent of CETA and Washington's clean energy policy.[97]

46 NWEC argues that the A&A Agreement between PSE and NorthWestern requires Commission approval pursuant to RCW 80.12.020. NWEC asserts that PSE's argument that Colstrip will no longer be necessary or useful in its duties to the public as of December 31, 2025, is circular, because PSE is abandoning Colstrip to NorthWestern as of the date of that agreement and suggests that if PSE's interpretation is correct, then every abandonment agreement would evade Commission review.[98] NWEC contends that, even if PSE's interpretation is correct, the Commission is still required to approve the agreement because PSE agreed to align its voting with NorthWestern as part of the A&A Agreement.[99] While NWEC states that it is not asking the Commission to void the A&A Agreement, it maintains that the Commission should not allow PSE to both avoid review of the A&A Agreement and fully recover costs that allow Colstrip to continue operating beyond December 31, 2025.[100]

47 AWEC argues that the Commission has authority to review the A&A Agreement pursuant to RCW 80.12.020. AWEC asserts that Colstrip cannot both be a regulatory asset subject to ratemaking treatment and not subject to the Commission's approval under RCW 80.12.020 with respect to its transfer to NorthWestern.[101] AWEC maintains that, if PSE's transfer of Colstrip is not subject to Commission approval, then Colstrip is a merchant power plant that is not eligible for recovery of undepreciated investment under RCW 19.405.030.[102] AWEC contends that it is unreasonable for PSE to request full recovery of its investments in Colstrip while also transferring its ownership of Colstrip to NorthWestern without

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[95] Brief of PSE at 27-28 ¶ 49; Roberts, TR. at 106:15-18.

[96] Brief of PSE at 27-28 ¶ 49; Roberts, Exh. RJR-1T at 9:15 – 10:3.

[97] Brief of PSE at 27 ¶ 47; Roberts, Exh. RJR-1T at 10:9-12.

[98] Brief of NWEC at 11-12 ¶ 27.

[99] Brief of NWEC at 12 ¶ 28.

[100] Brief of NWEC at 12 ¶¶ 29-30.

[101] Brief of AWEC at 3 ¶ 7.

[102] Brief of AWEC at 3 ¶ 7.

Commission oversight.[103] AWEC further cautions against relying on the timing of the Colstrip ownership transfer as a basis to not approve the transaction, as the timing may imply that Colstrip is operating as a merchant plant.[104]

48 AWEC maintains that the Commission should find PSE's reasons for entering into the A&A Agreement unpersuasive and states that if PSE is correct that Colstrip is of no value, then the plant should be immediately retired.[105] AWEC states that PSE's transfer of its Colstrip ownership to NorthWestern at no cost is not supported by economic analysis and is undermined by the decommissioning and remediation obligations that PSE retains under the A&A Agreement.[106] AWEC argues that the A&A Agreement is not in the public interest because it provides no value to Washington customers and requires PSE to surrender its discretion to NorthWestern for the benefit of NorthWestern's ratepayers.[107] AWEC further asserts that PSE could have elected to operate Colstrip as a merchant plant, that the Commission should not find the Company's arguments about the risks of operating Colstrip as a merchant plant persuasive, and that PSE chose to not operate Colstrip as a merchant plant to protect its shareholders.[108]

49 Both AWEC and Public Counsel recommend that the Commission require PSE to submit a separate filing to approve the A&A Agreement.[109]

Commission Determination

50 RCW 80.12.020(1) provides:

> No public service company shall sell, lease, assign or otherwise dispose of the whole or any part of its franchises, properties or facilities whatsoever,

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[103] Brief of AWEC at 3 ¶ 7.

[104] Brief of AWEC at 4 ¶ 8. The Commission declines to consider the testimony filed in another docket cited by AWEC. This evidence is not part of this record in this proceeding and the Commission has already rejected a prior attempt to refer to related testimony that has not been made part of the record. *See WUTC v. Avista Corp.*, Docket UE-240891, Order 06 (Sept. 30, 2025) (striking reference to testimony in Docket UE-240729 because the testimony had not been made part of the record).

[105] Brief of AWEC at 5-6 ¶¶ 10-11; Mullins, Exh. BGM-1T at 3:2-4.

[106] Brief of AWEC at 5-6 ¶ 11.

[107] Brief of AWEC at 5-6 ¶ 11; Mullins, Exh. BGM-1T at 7:10-17.

[108] Brief of AWEC at 6 ¶ 12.

[109] Dreyer, Exh. JMD-2CT at 3:11 – 4:12; Mullins, Exh. BGM-1T at 12:21 – 13:3.

> which are necessary or useful in the performance of its duties to the public, and no public service company shall, by any means whatsoever, directly or indirectly, merge or consolidate any of its franchises, properties or facilities with any other public service company, without having secured from the commission an order authorizing it to do so. The commission shall not approve any transaction under this section that would result in a person, directly or indirectly, acquiring a controlling interest in a gas or electrical company without a finding that the transaction would provide a net benefit to the customers of the company.

51 For RCW 80.12.020(1) to apply, the property that a public service company seeks to "sell, lease, assign or otherwise dispose of," must be "necessary or useful in the performance of [the public service company's] duties to the public." Pursuant to RCW 19.405.030(1)(a), each electric utility must eliminate coal-fired resources from its allocation of electricity on or before December 31, 2025, such that the costs and benefits associated with coal resources are removed from the electric utility's retail customer rates.[110]

52 During this proceeding, PSE updated its A&A Agreement to make the transfer of its Colstrip ownership to NorthWestern effective as of 12:00 a.m. Pacific Time, January 1, 2026.[111] As such, PSE's transfer of its Colstrip ownership to NorthWestern will occur after CETA's requirement to remove coal from the Company's allocation of electricity takes effect. Importantly, PSE has preserved its Colstrip transmission rights through the A&A Agreement.[112]

53 In general, every transfer of property that is useful and necessary from a public service company to another entity is subject to Commission approval pursuant to RCW 80.12.020. However, by prohibiting the use of certain resources for service in Washington, CETA has a unique interaction with the transfer of property statute, insofar as CETA effectively makes certain generating resources neither necessary or useful for service after a specific point in time. For coal-fired resources, that point in time is December 31, 2025.[113] Consequently, the Commission determines that the A&A Agreement is not subject to Commission approval pursuant to RCW 80.12.020 because, at the time PSE's Colstrip ownership is transferred to NorthWestern, Colstrip will not be "necessary or useful in the

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

[111] PSE's Supplemental Response to BR 3 (October 2, 2025).

[112] Roberts, Exh. RJR-1T at 6:14-15; Roberts, TR. at 98:15 – 99:1.

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

performance of [PSE's] duties to the public," other than the Colstrip transmission rights, which the Company has retained.[114]

54 The Commission is cognizant of the fact that this conclusion is unique and unusual. However, as will be addressed elsewhere in this Order, the fact that the Commission is not reviewing the A&A Agreement for approval does not mean that the Commission will refrain from examining actions taken pursuant to the A&A Agreement under other Commission standards. The Commission's determination that the A&A Agreement is not subject to review because Colstrip's generation will not be necessary or useful in the performance of PSE's duties to the Washington public is consistent with RCW 19.405.030(3)'s requirement that coal-fired resources be removed from PSE's allocation of electricity. Moreover, the Commission is not without recourse to fashion alternative review mechanisms pursuant to its statutory duty to regulate in the public interest.[115]

55 In order to facilitate future review of the transfer of property that will become unable to serve Washington customers in the future due to the requirements of CETA, including but not limited to RCW 19.405.030-.050, the Commission shall require PSE to comply with the following condition:

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

56 As the Commission has determined that the A&A Agreement is not subject to approval under RCW 80.12.020, it is unnecessary to resolve the arguments regarding whether PSE could have operated its portion of Colstrip as a merchant plant. However, the Commission observes that PSE presented credible evidence that the Company faced financial and legal risks if it elected to operate Colstrip as a merchant plant, PSE had a difficult bargaining position with respect to Colstrip, and PSE had made previous efforts to transfer its Colstrip

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[114] *See also* Mullins, Exh. BGM-1T at 10:7-12 ("If the transaction occurs prior to 12:00 Midnight on January 1, 2026, the deadline to remove coal from rates, then the transaction must, without question, be considered to involve utility plant subject to the property disposition requirements. If it occurs after 12:00 Midnight on January 1, 2026, then the transaction could potentially, but not necessarily, be viewed as a transaction of a merchant plant not subject to the approval process.").

[115] RCW 80.01.040.

ownership prior to the A&A Agreement.[116] Furthermore, insofar as CETA prohibits the cost and benefits from coal-fired resources to be included in retail electric customer rates, it is unclear how the operation of Colstrip as a merchant plant would have any direct or indirect value to PSE's Washington customers. There is no analysis in the record before the Commission regarding what those benefits could be, and the Commission will not presume that such benefits exist in the absence of supporting evidence. Finally, issues regarding decommissioning and remediation costs are not properly before the Commission in this case and will be reviewed in a later proceeding when such costs are proposed for inclusion in rates.

IV. Investments in Colstrip

57 As an initial matter, the discussion of PSE's Colstrip investments is somewhat complicated by the fact that different parties propose different categorizations of investments based on their respective positions. While there is some overlap between the parties' organization of investments and issues, the parties' organizations do not necessarily follow a uniform pattern. Therefore, the Commission will proceed by giving a brief overview of the parties' various positions and identify what assets each party has grouped under their respective categories in the interest of clarity.

PSE – Initial Position

58 PSE states that the purpose of this filing is to seek a determination of prudence and cost recovery for capital investments placed into service in 2024 through Schedule 141COL that are currently subject to refund.[117] PSE explains that it attempted to avoid including any capital investments that were expected to close in 2025 to minimize forecasting, although its filing does contain four projects that had closings in 2024 that are anticipated to be in service in 2025.[118] The Company further indicates that a final reporting of capital

[116] Roberts, Exh. RJR-1T at 3:19 – 8:6, 9:3 – 10:8; Roberts, TR. at 94:20 – 96:22. However, the Commission expresses concern that PSE omitted the fact that Colstrip had received an exemption to the MATS compliance obligations from its testimony. Roberts. TR. at 90:1-3. ("Q: Okay. And Colstrip received an exemption from the EPA's MATS, correct? A: After the abandonment agreement was reached, yes."). The Commission expects a greater degree of candor from the utilities that it regulates, and the lack of documentation regarding the MATS exemption for Colstrip is unavailing when PSE's own witness verified that an exemption had been granted. A lack of forthrightness may subsequently impact a party's credibility before the Commission.

[117] Atwood, Exh. NLA-1T at 2:7-11, 5:22-23.

[118] Atwood, Exh. NLA-1T at 5:23-25 fn. 11. *See also* Atwood, Exh. NLA-5C; Cebulko, Exh. BTC-1CT at 19:6-11 (identifying the four projects with 2025 in service dates as (1) U4 Generator Exciter; (2) Replacement 3X3 Startup Transformer; (3) 3-5 Feedwater Heater; and (4) Northern Chyenne AAQ System).

investments that are placed into service beyond the investments included in this filing will be made in its annual reports filed on or before September 30, 2025, and in 2026 after PSE has applied unrecovered plant against Production Tax Credits (PTC).[119]

59 PSE further argues that it has demonstrated that the costs the Company seeks to include in rates are prudent. The Company argues that it has demonstrated the need for its Colstrip investments based on its contractual obligations, the Colstrip operator's evaluation of the plan and cost benefit analysis, and the relatively high cost of replacement power.[120] The Company asserts that its decision to vote "no" on certain 2024 Colstrip budget items reflects PSE's attempt to consider alternatives to further capital additions, but that it cannot control the budgeting process based on its minority ownership share in Colstrip.[121] PSE further testifies that it coordinated with and kept its management reasonably informed about the investments at Colstrip.[122] Finally, PSE states that it has provided relevant contemporaneous documentation regarding the Colstrip costs in this proceeding.[123]

Staff

60 Staff does not challenge PSE's recovery of three categories of costs associated with Colstrip, totaling 25 projects. First, Staff does not contest ten projects with de minimis costs, defined by Staff as projects included in the Colstrip tracker that were less than $50,000, because these projects are not likely to have a material impact on rates.[124] Second, Staff does not challenge six projects associated with human health and safety concerns because "Staff accepts that the near-term benefits of those projects exceed the costs of the investments."[125] Third, Staff declines to challenge seven routine maintenance projects with

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[119] Atwood, Exh. NLA-1T at 6:1-5.

[120] Atwood, Exh. NLA-1T at 7:10 – 8:11, 10:17 – 11:9, 14:15 – 15:6; Exh. NLA-7C.

[121] Atwood, Exh. NLA-1T at 16:10 – 18:19.

[122] Atwood, Exh. NLA-1T at 20:8-17.

[123] Atwood, Exh. NLA-1T at 21:1-8; Exh. NLA-7C; Exh. NLA-10C.

[124] McGuire, Exh. CRM-1T at 8:1 – 9:5. Staff further explains that while at least one other project, the Northern Cheyenne AAQ system, met Staff's criteria for de minimis projects, Staff is contesting that project because the Company has not demonstrated that it is used and useful for service. McGuire, Exh. CRM-1T at 8:7-12. Staff states that the 10 de minimis projects consist of: (1) Opacity Monitor Replacement; (2) PLC to DCS Obsolescence; (3) Paste Plant Overflow Structure Mod; (4) Mercury Monitor Replacement U3; (5) Mercury Monitor Replacement U4; (6) River Pump Motor; (7) Boiler Feed Pump Rebuild; (8) PA Fan Motor Rewind; (9) Boiler Feed Booster Pump; and (10) Motor Circ Water Pump Cap. McGuire, Exh. CRM-1T at 8:14-20.

[125] McGuire, Exh. CRM-1T at 9:9 – 11:5. Staff identifies the six human health and safety projects as: (1) Switchgear modification; (2) U4 Boiler Snubber Rebuild; (3) Coal Pipe Replacement; (4) U4

an expected service life of four years or less,[126] reasoning that the Commission has previously distinguished between life-extending investments and routine capital maintenance and arguing that routine capital maintenance may be more appropriate for inclusion in rates.[127] Staff confirms that all of the projects that it is not contesting were placed into service during 2024.[128]

61 Staff challenges 13 of the 38 projects that PSE seeks to recover in this proceeding across three categories of assets.[129] First, Staff argues that the Commission should disallow one project related to the SmartBurn NOx Control System.[130] Second, Staff contends the Commission should disallow two projects that will not be used and useful in Washington in 2025.[131] Third, Staff asserts that the Commission should prorate ten projects that represent investments in long-lived plant.[132]

Projects Not Used and Useful

62 Staff maintains that the Commission should disallow recovery of the Unit 4 Generator Exciter and Northern Cheyenne AAQ System because the Company has not demonstrated that those investments are used and useful for service in Washington. Staff asserts that PSE has only identified estimated in-service dates for these two capital projects, which is insufficient to establish that the capital assets will be used and useful in Washington.[133]

Hot Reheat Elbow Replacement; (5) U4 Boiler Scaffolding; and (6) U4 Boiler Elevator. McGuire, Exh. CRM-1T at 9:15-20.

[126] McGuire, Exh. CRM-1T at 12:3-7 (identifying the routine maintenance projects as: (1) U4 Auxiliary Turbine Overhaul; (2) U4 Turbine/Generator Base Overhaul; (3) U4 Boiler Coutant Bottom; (4) U4 Air Preheater Basket Replacement; (5) U4 Boiler Waterwall Replacement; (6) U4 Boiler Economizer Tube Replacement; and (7) U4 Air Preheater Seal Replacement).

[127] McGuire, Exh. CRM-1T at 11:9 – 13:3. Staff further clarifies that while 18 of PSE's projects met its criteria for routine maintenance, 11 of the projects either have de minimis costs (four projects), were human health and safety projects (four), or were related to SmartBurn (three). McGuire, Exh. CRM-1T at 11:16 – 12:2. Staff subsequently revised its position and determined that two of the three investments that were originally categorized as SmartBurn should be recovered in full through rates as expenses related to routine maintenance. Brief of Staff at 5 ¶ 13.

[128] McGuire, Exh. CRM-1T at 7:17-20.

[129] McGuire, Exh. CRM-1T at 6:19 – 7:3.

[130] Brief of Staff at 3 ¶ 9.

[131] McGuire, Exh. CRM-1T at 13:11-12.

[132] McGuire, Exh. CRM-1T at 13:13-15.

[133] Brief of Staff at 6-7 ¶ 15; Atwood, Exh. NLA-11T at 19:15-20 (*citing* Atwood, Exh. NLA-14); Atwood, TR. at 77:10 – 79:12.

Alternatively, Staff argues that, if the Company demonstrates that these projects are in service after the close of evidence in this proceeding, the Commission should only allow a prorated portion of those investments into rates based on the length the projects are in service prior to the CETA cut-off relative to the total service life of the assets.[134]

63 Staff further disagrees that the Commission's Used and Useful Policy Statement supports PSE's argument for full recovery of the capital investments in this proceeding. Staff contends that simply because the capital investments may be used and useful for some time prior to CETA's requirement to remove coal power from PSE's allocation of electricity does not mean that PSE is entitled to recover the full cost of the investment.[135] Moreover, Staff states that allowing PSE to recover costs in rates associated with projects in service after 2025 would be unreasonable and contrary to Washington law.[136] Staff further argues that it is not unfair for the Commission to require PSE to pay for costs that it is obligated to pay under its O&O Agreement, because PSE, rather than the ratepayers, had full control over whether to enter such an agreement and there is nothing unfair about requiring PSE to honor its contractual commitments.[137]

Long-Lived Plant Assets

64 Staff contends that the Commission should prorate the costs associated with ten long-lived assets because PSE has not demonstrated that the ten long-lived assets were prudent and not life extending.[138] First, Staff asserts that while the investments provide some benefit to Washington customers, the investments will not be able to provide the full benefit associated with their respective useful lives due to CETA's prohibition on coal power in PSE's allocation of electricity.[139] For support, Staff refers to the Commission's final order in Avista's 2020 GRC, where the Commission rejected Avista's request to recover costs of its Dry Ash Disposal Project because Avista had not shown that the project was not life-

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[134] Brief of Staff at 6-7 ¶ 15.

[135] Brief of Staff at 7-8 ¶ 16.

[136] Brief of Staff at 7-8 ¶ 16.

[137] Brief of Staff at 8 ¶ 17.

[138] Brief of Staff at 8-9 ¶ 19 fn. 37 (identifying the ten long-lived assets as: (1) CEM Monitor replacement for U4; (2) Scrubber Chiller replacement; (3) Windows 11 Workstation Upgrades; (4) CRO Simulator replacement, (5) Mobile Equipment replacements for 2024; (6) Replacement 3x3 Startup Transformer; (7) 3-5 Feedwater Heater; (8) Vehicle replacements for 2024; (9) EHP G Cell Liner Purchase; and (10) Cooling Tower Fill replacement for U4).

[139] Brief of Staff at 10 ¶ 22.

extending.[140] Staff maintains that because CETA prohibits coal in the Company's allocation of electricity beginning in 2026, the Company should only be authorized to recover a proportional share of costs associated with long-lived assets because they will only benefit Washington customers for a portion of their overall useful life.[141]

65 Second, Staff argues that PSE has not demonstrated a need for the ten long-lived investments. Staff notes that even though PSE voted against several capital additions during the Colstrip budgeting process, which indicates a lack of need, the Company is nonetheless seeking full recovery of those investments in this proceeding.[142] According to Staff, although PSE was obligated to pay for its proportional share of approved investments pursuant to the O&O Agreement, the existence of the agreement is not determinative as to the need for a particular investment.[143] Staff further contends that the lack of discretion to fund approved budget items under the O&O Agreement is insufficient to demonstrate need and that PSE's decision to vote against including certain long-lived assets in the Colstrip budget shows that such investments were unnecessary.[144]

66 Third, Staff maintains that PSE has not identified a valid cost-benefit analysis demonstrating that the projects are likely to produce sufficient benefits relative to the costs of the projects. Staff argues that the Commission's prior decisions in PacifiCorp's 2005 GRC and Avista's 2015 GRC establish that a utility must provide a cost-benefit analysis that quantifies tangible and intangible benefits to demonstrate that an investment is prudent.[145] Staff notes that PSE testified that whether benefits exceed costs is a relevant consideration for utility management when choosing to pursue investments and that such analysis should be from the perspective of Washington ratepayers.[146]

67 Staff also contends that, while PSE did provide a NPV calculation to demonstrate that the Company considered the costs and benefits of investments, the NPV analysis is flawed because it assumes a 100 percent probability of asset failure that will result in an outage if

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[140] Brief of Staff at 10 ¶ 23 fn. 46 (*citing WUTC v. Avista Corp*., Dockets UE-200900, UG-200901, & UE-200894 (*consolidated*), Order 08/05 at 100 ¶ 279 (Sept. 27, 2021)).

[141] Brief of Staff at 11 ¶ 24.

[142] Brief of Staff at 12-13 ¶¶ 27-28.

[143] Brief of Staff at 12-13 ¶ 27.

[144] Brief of Staff at 13 ¶ 28.

[145] Brief of Staff at 13-14 ¶ 30 (*citing WUTC v. Avista Corp*, Dockets UE-150204 & UG-150205 (*consolidated*), Order 05 at 69 ¶ 193 (Jan. 6, 2016); *WUTC v. PacifiCorp*, Dockets UE-050684 & UE-050412 (*consolidated*), Order 04/03 at 27-28 ¶ 68 (Apr. 27, 2006)).

[146] Brief of Staff at 15 ¶ 32 (*citing* Atwood, TR. at 37:17-21, 38:4-7).

the investment is not pursued.[147] Staff asserts that assuming a 100 percent probability of failure if a replacement is not acquired overstates the actual probability of failure, thereby artificially increasing the benefits associated with a particular investment.[148] Staff states that PSE is unable to identify the actual probability of failure because Talen does not model the probability of failure.[149] Staff also states that PSE's NPV analysis is unreasonable because it is not from the perspective of Washington ratepayers.[150] Staff further maintains that PSE has not adequately supported its assertion that the cost of short term power would exceed the cost of further capital investment in Colstrip.[151] Finally, Staff argues that PSE has not demonstrated that it adequately presented data to management regarding decisions to pursue investments at Colstrip.[152]

SmartBurn

68 Staff initially recommended that the Commission disallow recovery of the Unit 4 Boiler Burner AuxAir Replacement (Boiler Burner), the Unit 4 separated air over fire (SOFA) Bucket Replacement, and the Unit 4 Top Over Fire Air Bucket Replacement (TOFA), which Staff initially identified as SmartBurn components that were disallowed in PSE's 2019 GRC.[153] However, after receiving PSE's answer to BR 2, Staff revised its recommendation to support recovery for the SOFA and Boiler Burner but to disallow recovery for the TOFA component because it had been previously disallowed in PSE's 2019 GRC as a SmartBurn component.[154]

Public Counsel

69 Public Counsel asserts that PSE's attempt to seek full cost recovery of "life-extending" investments at Colstrip is improper because these investments will support Colstrip operations beyond 2025, after which CETA prohibits inclusion of coal-fired resources in PSE's allocation of electricity. Public Counsel recommends that the Commission broadly prorate all of PSE's 2024 Colstrip investments so that customers only pay for a share of

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[147] Brief of Staff at 15 ¶ 33; McGuire, Exh. CRM-1T at 20:4 - 24:4.

[148] Brief of Staff at 15-16 ¶ 34.

[149] Brief of Staff at 15-16 ¶ 34; McGuire, Exh. CRM-4 at 2.

[150] McGuire, CRM-1T at 19:6-10, 20:16 – 21:19.

[151] Brief of Staff at 17-18 ¶ 36.

[152] Brief of Staff at 16-17 ¶ 35.

[153] McGuire Exh. CRM-1T at 3:8-10, 13:22-23, 14:1-2, 14:13-18.

[154] Brief of Staff at 3 ¶ 9.

each plant addition proportional to their share of that plant's additional expected service life prior to the deadline to remove coal-fired resources from rates.[155] Public Counsel further argues that the Commission should entirely disallow the TOFA project related to SmartBurn.[156]

Used and Useful

70 Public Counsel argues that Colstrip will not be used and useful to Washington ratepayers after December 31, 2025, and that costs associated with capital additions related to Colstrip operations after that date must be excluded from rates. Stated another way, Public Counsel contends that Colstrip "capital additions can only be placed into rates to the extent they were in service to Washington customers through the end of 2025."[157] Public Counsel maintains that while the Legislature modified the Commission's ratemaking authority when it enacted CETA to allow the Commission to consider rate base that will be used and useful up to 48-months after the rate effective date, the assets must still be capable of being used for service in Washington to be included in rate base.[158]

Life-Extending Investments

71 Public Counsel states that PSE has failed to demonstrate that its investment in life-extending capital additions to Colstrip were prudent. Public Counsel argues that several capital additions that extend the useful life of Colstrip beyond December 31, 2025, when Colstrip can no longer provide coal power to PSE's Washington customers, are unreasonable and therefore imprudent.[159] Public Counsel further asserts that including costs associated with Colstrip capital assets in service beyond 2025, when Washington customers cannot benefit from those assets, results in rates that are not fair, just, reasonable, and sufficient. Public Counsel contends that including the full costs of PSE's Colstrip investments is unfair because they cannot benefit Washington customers after 2025, unjust because inclusion is contrary to CETA and the used and useful principle, and unreasonable because Colstrip provides no value to Washington customers and is harmful to the

[155] Dreyer, Exh. JMD-1CTr at 5:19 – 6:6. *See also* Dreyer, Exh. JMD-2CT at 5:1-7 (supporting AWEC's general proposal to prorate PSE's 2024 capital additions).

[156] Brief of Public Counsel at 23 ¶¶ 69-70.

[157] Brief of Public Counsel at 14-15 ¶ 45.

[158] Brief of Public Counsel at 14-15 ¶¶ 44-45.

[159] Brief of Public Counsel at 18 ¶ 55; Dreyer, Exh. JMD-1CTr at 4:23 – 5:18.

environment.[160] Public Counsel also maintains that the Company has not presented any evidence that allowing only a prorated portion of its Colstrip capital additions into rates will result in insufficient revenue for the Company to continue operating.[161] Based on its above arguments, Public Counsel recommends that the Commission allow recovery of PSE's Colstrip assets on a prorated basis.[162]

SmartBurn

72 Public Counsel recommends that the Commission disallow recovery for all four of the NOx components, including the Boiler Burner, SOFA, TOFA, and Control Room Operator (CRO) because the Commission had previously found SmartBurn to be imprudent.[163] After review of PSE's response to BR 2, Public Counsel maintains its position that SmartBurn investments that were disallowed in PSE's 2019 GRC cannot be recovered in this matter.[164] However, because only the TOFA component was disallowed in the 2019 GRC, Public Counsel now recommends the Commission disallow recovery only of the TOFA investment.

NWEC

73 NWEC makes six general recommendations regarding PSE's Colstrip investments at issue in this proceeding. First, NWEC argues that the Commission should disallow costs associated with projects that extend the life of Colstrip such that it will continue to operate past December 31, 2025.[165] Second, NWEC states that the Commission should disallow

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[160] Brief of Public Counsel at 18-19 ¶¶ 57-59.

[161] Brief of Public Counsel at 19-20 ¶ 60.

[162] Brief of Public Counsel at 24-26 ¶¶ 74-80; Dreyer, Exh. JMD-1CTr at 5:19 – 6:6.

[163] Dreyer, Exh. JMD-2CT at 3:4-8.

[164] Brief of Public Counsel at 23 ¶¶ 69-70.

[165] Cebulko, Exh. BTC-1CT at 22:1-10, 25:8-9 (identifying nine life-extending investments as (1) Scrubber Chiller Replacement; (2) CEM Monitor Replacement – U4; (3) Opacity Monitor Replacement; (4) Cooling Tower Fill Replacement U4; (5) Mercury Monitor Replacement – Unit 3; 6) Mercury Monitor Replacement – Unit 4; 7) EHP G Cell Liner Purchase; (8) PLC to DCE Obs. (Water Treatment Conversion); and (9) River Pump Motor). *See also* Brief of NWEC at 4 ¶ 10 (clarifying that NWEC also considers the four projects not used and useful prior to 2025 to also be life extending investments, bringing the total number of life-extending investments that NWEC recommends the Commission disallow to thirteen).

projects that lack a capital justification.[166] Third, NWEC asserts that the Commission should allow PSE to recover only a prorated portion of costs associated with eleven major maintenance projects.[167] Fourth, NWEC contends that the Commission should disallow costs associated with the TOFA and SOFA investments related to SmartBurn.[168] Fifth, NWEC maintains that the Commission should disallow recovery of four investments that were not placed into service in 2024.[169] Finally, similar to Staff, NWEC recommends that the Commission allow full recovery of six projects associated with human health and safety.[170]

Life-Extending Investments

74 NWEC argues that the Commission should not allow PSE to recover costs associated with life-extending investments at Colstrip. NWEC contends that PSE has not demonstrated that 13 life-extending projects are used and useful for service in Washington.[171] NWEC further asserts that the fact that PSE has entered into the A&A Agreement with NorthWestern should not influence the Commission's analysis regarding whether the assets are used and useful.[172] NWEC maintains that PSE's decision to vote against various Colstrip capital additions undermines the Company's assertion that those assets are prudent.[173] NWEC

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[166] Cebulko, Exh. BTC-1CT at 26:1-2 (identifying projects lacking capital justification as (1) Boiler Feed Pump Rebuild-Element; (2) PA Fan Motor Rewind/Refurb; (3) Boiler Feed Booster Pump RB; and (4) Motor Circ Wtr Pump Cap Spare).

[167] Cebulko, BTC-1CT at 28:15 – 29:1 (identifying major maintenance projects as: (1) Auxiliary Turbine Overhaul U4; (2) Turbine/Generator Base OH U4; (3) Boiler Coutant Bottom U4; (4) Air Preheater Basket Repl U4; (5) Boiler Waterwall Repl/Maint U4; (6) Air Preheater Seal Repl; (7) Workstation Upgrades (Windows 11); (8) Mobile Equipment replacements (2024); (9) Paste Plant Overflow Structure Modifications; (10) Boiler Economizer Tube Repl U4; and (11) Vehicle Replacements (2024)). Seven of NWEC's major maintenance projects are the same as the "routine maintenance" projects identified by Staff. *Compare* McGuire, Exh. CRM-1T at 23:3-7 *with* Cebulko, Exh. BTC-9CT at 8:1.

[168] Brief of NWEC at 8 ¶ 19.

[169] Cebulko, Exh. BTC-1CT at 19:6-11 (identifying the four projects as (1) U4 Generator Exciter; (2) Replacement 3X3 Startup Transformer; (3) 3-5 Feedwater Heater; and (4) Northern Chyenne AAQ System).

[170] *Compare* McGuire, Exh. CRM-1T at 8:14-20 *with* Cebulko, Exh. BTC-1CT at 27:7-8.

[171] Brief of NWEC at 4-5 ¶¶ 11-12. Cebulko, Exh. BTC-1CT at 9:10 – 10:2, 12:10 – 13:6.

[172] Brief of NWEC at 5 ¶ 12.

[173] Brief of NWEC at 5 ¶ 12.

requests that the Commission should articulate a prudence standard that will apply to future investments that extend the life of fossil fuel resources.[174]

Investments Lacking Capital Justification

75 NWEC additionally recommends that the Commission disallow four projects that have no capital justification in the record. NWEC notes that PSE's request for recovery in this case contains four projects that were initially non-capital projects that were subsequently transferred to capital based on financial review that do not have specific capital justification summaries.[175] NWEC inquired further about the justification for these four projects in discovery, but received a similar response from PSE, who indicated that no capital justifications were available.[176] NWEC recommends that the Commission disallow costs associated with these four projects because PSE has neither demonstrated the need for nor provided contemporaneous documentation regarding these projects.[177]

Major Maintenance

76 NWEC also recommends that the Commission prorate major maintenance projects associated with Colstrip capital investments and disallow costs amortized after 2025, consistent with the term in the Settlement Agreement in PSE's 2022 GRC regarding major maintenance, for three reasons.[178] First, NWEC states that plant investments have generally been recovered based on the expected life of the investment, and that prorating recovery of maintenance costs appropriately matches the investments costs with its expected benefits.[179] Second, NWEC contends that allowing full recovery of maintenance costs would conflict with PSE's 2014 and 2022 settlement terms regarding the amortization of major maintenance costs, which provide that major maintenance will be amortized over three years and, in the case of the 2022 settlement, that costs amortized after 2025 will not

[174] Supp. Brief of NWEC at 4 ¶ 11.

[175] Cebulko, Exh. BTC-1CT at 25:13-18 (*citing* Atwood, Exh. NLA-1T at 11:1 fn. 17).

[176] Cebulko, Exh. BTC-7 at 1 (stating for each of the four projects "No Capital Justification available, inspection based work after removal.").

[177] Cebulko, Exh. BTC-1CT at 26:6-8.

[178] Cebulko, Exh. BTC-9CT at 6:1-19; Brief of NWEC at 7-8 ¶ 17 (*citing WUTC v. Puget Sound Energy*, Dockets UE-220066, UG-220067, & UE-210918 (*consolidated*), Order 24/10, Appendix A at 7-8 ¶ 23 j (Dec. 22, 2022)).

[179] Cebulko, Exh. BTC-9CT at 6:2-11.

be recovered.[180] Finally, NWEC argues that the NPV analysis overstates the benefits from Colstrip because it overestimates the availability of Colstrip power, fails to consider the cost of capital investments in its comparison of benefits to costs, and improperly assumes that PSE's only reasonable alternative was to purchase replacement power from the market.[181] NWEC supports Staff's argument that the NPV analysis improperly assumes a 100 percent probability of failure in the event that a capital asset is not pursued.[182] NWEC further maintains that the Commission should not rely on the late disclosed analysis provided by PSE in response to BR 1 because that analysis is not risk adjusted and PSE has not shown that it was prepared contemporaneously with its decisions to invest in Colstrip.[183]

SmartBurn

77 NWEC argues that the Company has not provided any new evidence demonstrating that its SmartBurn investments have been prudently incurred.[184] NWEC also raises concerns about the Company requesting relief for an investment that has been previously disallowed by the Commission and alleged that the request places an "undue and significant burden on the Commission and intervenors" as it makes it difficult to obtain a reasonable settlement.[185]

78 NWEC contends that the Company has not provided support that distinguishes the SOFA component from the TOFA component. NWEC raises concern that "the arrows in PSE's schematic[186] identify the same part of the boiler system in attempting to delineate between TOFA and SOFA, making it impossible for the viewer to determine what, if any, difference exists between the TOFA and SOFA components."[187] NWEC recommends that the

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[180] Cebulko, Exh. BTC-1CT at 29:2 – 30:2 (*citing WUTC v. Puget Sound Energy*, Docket UE-141141, Order 04 at 3-5 ¶ 8 (Nov. 3, 2014)); Cebulko, Exh. BTC-9CT at 6:12-17 (*citing WUTC v. Puget Sound Energy*, Dockets UE-220066, UG-220067, & UE-210918 (*consolidated*), Order 24/10, Appendix A at 7-8 ¶ 23 j (Dec. 22, 2022)).

[181] Brief of NWEC at 5-6 ¶ 13; Cebulko, Exh. BTC-1CT at 13:15 – 16:16.

[182] Brief of NWEC at 6 ¶ 14 (*citing* McGuire, Exh. CRM-1T at 22:1 – 24:4).

[183] Brief of NWEC at 6-7 ¶ 16.

[184] Cebulko, Exh BTC-1CT at 18:12-15.

[185] McCloy, Exh. LCM-1T at 12:16-20.

[186] The schematic identified by NWEC was filed September 10, 2025, by the Company in response to BR 2 Attachment A and is marked confidential.

[187] Brief of NWEC at 9-10 ¶ 22.

Commission should disallow the SOFA and TOFA components as SmartBurn that has been previously disallowed.[188]

Investments Not Used and Useful in 2024

79 NWEC maintains that the Commission should fully disallow four projects with in-service dates in 2025 because PSE cannot demonstrate that these investments provided benefits to Washington ratepayers in 2024.[189] NWEC asserts that projects that come online on December 31, 2025, will never provide benefits to Washington ratepayers due to CETA's requirement to remove coal-fired resources from the allocation of electricity.[190] NWEC also argues that, if the Commission determines that the four investments not used and useful in 2024 are in fact used and useful, that the Commission should classify the projects as life-extending and disallow recovery of those investments because their useful lives exceed the three to four year useful life for major maintenance projects.[191]

Human Health and Safety Investments

80 NWEC recommends that the Commission allow PSE to recover six projects associated with human health and safety concerns.[192] NWEC states that it has reviewed the project justifications for each of the projects and found that the projects included economic metrics, including such as the internal rate of return and estimated payback period, and verified that the project descriptions supported a safety designation.[193] As such, NWEC recommends full recovery of the six human health and safety projects.[194]

AWEC

81 AWEC recommends that the Commission should prorate PSE's recovery of assets based on the portion of their service life prior to December 31, 2025, because after that date the

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[188] Brief of NWEC at 9-10 ¶ 22.

[189] Cebulko, Exh. BTC-1CT at 19:1 – 20:6. *See also* Cebulko, Exh. BTC-1CT at 19:10-11 (identifying the projects with in service dates in 2025 as: (1) U4 Generator Exciter; (2) Replacement 3X3 Startup Transformer; (3) 3-5 feedwater heater; and (4) Northern Cheyenne AAQ System).

[190] Cebulko, Exh. BTC-1CT at 20:7-13.

[191] Brief of NWEC at 10 ¶ 24.

[192] Cebulko, Exh. BTC-1CT at 26:11 – 27:10.

[193] Cebulko, Exh. BTC-1CT at 27:1-6.

[194] Cebulko, Exh. BTC-1CT at 27:9-10.

assets are not used and useful in Washington and the Commission should disallow costs associated with the previously disallowed SmartBurn investment.

Used and Useful

82 AWEC asserts that the Commission should exclude capital projects that have an in-service date of December 31, 2025, or later under the used and useful standard, because those capital projects will not be used for service during the rate effective period.[195] Additionally, AWEC argues that the Commission should prorate PSE's recovery of life-extending investments, routine maintenance, and human safety projects, because those investments will not provide benefits to ratepayers after 2025.[196] AWEC further contends that a disallowance is appropriate given PSE's decision to enter into the A&A Agreement because the A&A Agreement obligated PSE to invest in life-extending assets that provide minimal benefit to Washington ratepayers.[197] AWEC states that any disallowance should be not be subject to cost recovery by using PTCs.[198]

SmartBurn

83 AWEC recommends that the Commission disallow all capital additions associated with SmartBurn that had been previously disallowed.[199] Specifically AWEC recommends disallowance for previously disallowed SmartBurn investments by a total of $1,039,987, which reflects only a disallowance for the TOFA component.[200]

PSE - Rebuttal

Used and Useful

84 The Company maintains that its capital investments in Colstrip satisfy the Commission's used and useful standard. Specifically, PSE argues that its investments comply with the Commission's Used and Useful Policy Statement and suggests that prorating its investments would be unjust given the Commission's prior approval of the settlement term

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[195] Brief of AWEC at 7-8 ¶ 15.

[196] Brief of AWEC at 8-9 ¶ 17.

[197] Brief of AWEC at 4-5 ¶ 9.

[198] Brief of AWEC at 4-5 ¶ 9; Mullins, Exh. BGM-1T at 4:5-9.

[199] Mullins, Exh. BGM-1T at 3:16-18.

[200] Brief of AWEC at 8 ¶ 16; Mullins, Exh. BGM-4C.

related to terminal depreciation of Colstrip assets.[201] The Company further asserts that proration of the Colstrip capital investments would be unfair, because the investments were necessary and provided a benefit to customers.[202] PSE maintains that the proposals to prorate the capital additions in this case contradict the settlement agreement in Dockets UE-170033 and UG-170034, as well as the settlement agreement in Dockets UE-220066, UG-220067, and UG-210918, because those agreements provide for terminal depreciation of the Colstrip assets.[203]

Live-Extending Investments

85 PSE asserts that the NPV analysis included in the Company's filing satisfies the Commission's prudence standard. The Company maintains that the NPV analysis reasonably reflects the costs associated with each project, risks associated with not performing the work, and the reasoning for each project.[204] PSE argues that the risk assessment reflected in the NPV analysis is appropriate because of the comparatively high cost of purchasing replacement power in the event of a temporary shut-down of Colstrip.[205] The Company further contends that, under its O&O Agreement, PSE's failure to pay its portion of Colstrip capital addition costs would have resulted in the Company defaulting on its contract and losing access to its share of electricity from Colstrip.[206] As a result of the threat of default, the Company argues that it effectively faced a 100 percent probability of failure if it failed to pay for its share of Colstrip capital addition costs. PSE further states that the Commission's prudence standard does not require a risk adjusted cost-benefit analysis in the manner proposed by Staff.[207]

Projects Not In Service Before 2025

86 PSE additionally argues that the Commission should allow the Company to recover assets that may not be in service before 2025. PSE suggests that the Commission's Used and Useful Policy Statement supports the Company's argument that the Commission has

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[201] Brief of PSE at 14-15 ¶ 26; Free, Exh. SEF-1T at 6:1 – 8:11, Atwood, Exh. NLA-11T at 18:6 – 19:20.

[202] Brief of PSE at 14-15 ¶ 26; Atwood, Exh. NLA-11T at 2:7-10.

[203] Brief of PSE at 12-14 ¶¶ 23-25; Free, Exh. SEF-1T at 6:1-21.

[204] Brief of PSE at 15 ¶ 27; Atwood, Exh. NLA-1T at 10:17 – 11:9, Exh. NLA-11T at 14:1 – 15:16.

[205] Brief of PSE at 15-16 ¶ 28; Atwood, Exh. NLA-1T at 15:7 – 16:8; Exh. NLA-11T at 14:7-12.

[206] Brief of PSE at 16-17 ¶ 29; Atwood, Exh. NLA-9.

[207] Brief of PSE at 17 ¶ 30; Atwood; Exh. NLA-11T at 11:1 – 13:6.

sufficient flexible authority under RCW 80.04.250 to permit recovery of its investments in the U4 Generator Exciter and Northern Cheyenne AAQ System.[208] The Company states that the Commission's rejection of more restrictive approaches to the inclusion of provisional capital in rates as part of the Used and Useful Policy Statement indicates that the Commission may include capital additions that are not in service by 2025 in rate base.[209]

Major Maintenance

87 PSE argues that the Commission should reject NWEC's argument to prorate or disallow major maintenance capital costs based on PSE's 2014 and 2022 settlements because those settlements do not apply to major maintenance capital costs. PSE maintains that major maintenance events result in two types of costs, capital costs and operations and maintenance (O&M) costs.[210] PSE asserts that the 2014 settlement only pertains to the O&M costs associated with major maintenance events, and that NWEC is attempting to improperly apply that settlement term to major maintenance capital costs.[211] However, while PSE contends that the 2014 settlement term does not apply to the capital maintenance costs, it states that the major maintenance amortization treatment in the 2014 settlement has the same effect as prorating the major maintenance capital costs.[212] PSE further argues that the 2022 settlement term regarding major maintenance amortization only pertains to the amortization of major maintenance O&M costs, not major maintenance capital costs, similar to the 2014 settlement.[213]

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[208] Brief of PSE at 21-22 ¶¶ 38-39; Atwood, NLA-11T at 17:18 – 19:20.

[209] Brief of PSE at 22 ¶ 39.

[210] Free, Exh. SEF-1T at 12:10-11.

[211] Free, Exh. SEF-1T at 13:3-8.

[212] Free, Exh. SEF-1T at 13:14-17 ("In other words – the treatment Mr. Cebulko and parties recommend for pro-rating PSE's capital costs is the same as the major maintenance *amortization* treatment agreed to in PSE's 2014 PCORC. Therefore, no correction to the calculation of Mr. Cebulko's proposed adjustment is needed.") (emphasis in original).

[213] Brief of PSE at 14-15 ¶ 26 fn.61; Free, TR. at 115:25 – 118:8. *See also* Free, TR. at 119:5-14 ("A: I believe that the way my exhibits were laid out in [PSE's 2022 GRC], the contested adjustment was only related to the O&M portion of major maintenance. That's deferred. Not the capital. And we settled that adjustment. So in my mind that makes it clear. Q: All right. So what you're saying is you only settled the operation/maintenance portion, not the capitalized portion? A: Correct.").

SmartBurn

88 The Company is seeking recovery of investments to components of its NOx control system. Specifically, the Boiler Burner, SOFA, and TOFA components of the combustion control system, which are commonly referred to as SmartBurn by the Colstrip operator and within plant budgets.[214] PSE alleges that there has been a misunderstanding as to what is the SmartBurn equipment that was disallowed in PSE's 2019 GRC because SmartBurn is a company and not a singular piece of equipment. [215] For regulatory purposes, PSE clarifies that the only components of the NOx control system that was disallowed as SmartBurn in PSE's 2019 GRC was the TOFA. The SOFA and Boiler Burners existed prior to the SmartBurn technology installation.[216] The Boiler Burner was installed prior to 2007, the SOFA on Unit 3 was installed in 2007, and on Unit 4 in 2009.[217] PSE concedes that the Company incorrectly identified the SOFA, TOFA, and Boiler Burners as SmartBurn in a data request response to Staff.[218] On cross-examination, although the Boiler Management System (BMS) was updated by SmartBurn in 2017, the plant would still need a BMS, regardless of who installed it.[219] PSE is not seeking any recovery related to the BMS in this docket.[220] Atwood alleges that the "CRO Simulator is not specific to the operation of SOFA-installed SmartBurn equipment only" and that the CRO would have been installed without a SmartBurn investment so it should not be disallowed.[221]

89 PSE is seeking recovery for the TOFA SmartBurn component even though it had previously been disallowed because the TOFA is "an integrated part of the Combustion Control system, and the plant cannot run without it."[222] Specifically:

> [t]he pieces of the combustion system work together to operate the Units efficiently by avoiding slagging, maintaining steam temperature, avoiding metal heat fatigue, and other goals, while also maintaining environmental compliance standards. TOFA, SOFA, burners, and other equipment all have to be maintained on a regular basis when in constant contact with heat and

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[214] Atwood, Exh. NLA-11T at 4:12-18.

[215] Atwood, Exh. NLA-11T at 5:4-8.

[216] Atwood, Exh. NLA-11T at 5:15-22; Atwood, TR. at 39:21-25; Atwood, Exh. NLA-12.

[217] PSE's Response to BR 2.

[218] Atwood, Exh. NLA-11T at 5:22, 6:1-3; Exh. NLA-7C.

[219] Atwood, TR. at 40:14-20.

[220] Atwood, Exh. NLA-19X at 1.

[221] Atwood, Exh. NLA-11T at 7:3-5, 13-15.

[222] Atwood, Exh. NLA-11T at 6:5-9.

corrosive conditions. Consequently, PSE should be allowed to recover the investment made in these systems and equipment.[223]

90 PSE argues that its investments in SmartBurn are prudent and are used and useful, and requests that the Commission grant full recovery.[224] Although the Commission previously disallowed the TOFA component, the Company argues that a previous disallowance is not a "blanket, forward-looking" ban and that the Commission should base its decision on the record in this proceeding and asks the Commission to consider whether the SmartBurn investments in "2024 were prudently incurred and confer commensurate benefits to Washington customers in the rate period[.]"[225]

Commission Determination

91 Before investments may be recovered in rates, the Commission must determine that the costs associated with investments a utility seeks to recover are used and useful for service in this state.[226] Similarly, costs may only be included in rates if the Commission determines those investments are prudent.[227] As such, the Commission review of a utility's requested rate recovery encompasses both the question of whether investments are used and useful and the question of whether the associated costs are prudent.[228] The Commission now proceeds to consider whether the investments that PSE has included in rates for recovery are used and useful and then considers whether the costs that it seeks to recover are prudent.

A. Used and Useful

92 RCW 80.04.250 states in part:

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[223] Atwood, Exh. NLA-11T at 6:10-16.

[224] Brief of PSE at 17-18 ¶ 31.

[225] Brief of PSE at 17-18 ¶ 31.

[226] *WUTC v. PacifiCorp,* Docket UE-050684, Order 04 at 21-22 ¶ 50 (Apr. 17, 2006).

[227] *WUTC v. Puget Sound Energy*, Docket UE-031725, Order 14 at 20-21 ¶ 37 (May 13, 2004) ("Any costs determined to be unreasonable or imprudent in such proceedings are subject to disallowance.").

[228] *See also* Policy Statement on Property that Becomes Used and Useful After the Rate Effective Date, Docket U-190531 at 14-15 ¶ 43 (Jan. 31, 2020) ("In sum, this Policy Statement establishes a two-step approval process. The first step involves provisional approval for the inclusion in rates of identified rate-effective period investment. The second step involves final approval after the investments are reviewed and confirmed to be used and useful and prudent.").

> (1) The provisions of this section are necessary to ensure that the commission has sufficient flexible authority to determine the value of utility property for rate making purposes and to implement the requirements and full intent of chapter 288, Laws of 2019.
>
> (2) The commission has power upon complaint or upon its own motion to ascertain and determine the fair value for rate making purposes of the property of any public service company used and useful for service in this state by or during the rate effective period and shall exercise such power whenever it deems such valuation or determination necessary or proper under any of the provisions of this title. The valuation may include consideration of any property of the public service company acquired or constructed by or during the rate effective period, including the reasonable costs of construction work in progress, to the extent that the commission finds that such an inclusion is in the public interest and will yield fair, just, reasonable, and sufficient rates.
>
> (3) The commission may provide changes to rates under this section for up to forty-eight months after the rate effective date using any standard, formula, method, or theory of valuation reasonably calculated to arrive at fair, just, reasonable, and sufficient rates. The commission must establish an appropriate process to identify, review, and approve public service company property that becomes used and useful for service in this state after the rate effective date.

The Commission further observes that this language reflects amendments the Legislature made during consideration of CETA, and those amendments are found in chapter 288, Laws of 2019, the same legislation that enacted CETA.[229]

93 In interpreting the phrase "used and useful," the Washington State Supreme Court has explained "'Used' is defined as 'employed in accomplishing something'; 'useful' is defined as 'capable of being put to use: having utility: advantageous: producing or having the power to produce good: serviceable for a beneficial end or object.'"[230] The Court further explained "RCW 80.04.250 empowers the Commission to determine, for ratemaking purposes, the fair value of property which is employed for service in Washington *and* capable of being put to use for service in Washington."[231] By extension, "[w]hen calculating a utility's rate base for ratemaking, if the WUTC considers utility plant that 'is neither employed for service nor capable of being put to use for service; . . . such plant is

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[229] See, e.g., RCW 19.405.010 (reflecting the title "Findings – Intent – 2019 c 288").

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

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

not 'used and useful' for service' and the [Commission] exceeds its statutory authority."[232] The Commission has also previously interpreted "the phrase 'used and useful for service in this state' to mean benefits to ratepayers in Washington, either directly (e.g., flow of power from a resource to customers) and/or indirectly (e.g., reduction of cost to Washington customers through exchange contracts or other tangible or intangible benefits)."[233]

94 However, the Commission's inquiry regarding the used and useful standard is further informed by the requirements of CETA. Specifically, RCW 19.405.030(1) states that "[o]n or before December 31, 2025, each electric utility must eliminate coal-fired resources from its allocation of electricity. This does not include costs associated with decommissioning and remediation." RCW 19.405.020(1) further defines "allocation of electricity" as, "for the purpose of setting electricity rates, the costs and benefits associated with the resources used to provide electricity to an electric utility's retail electricity consumers that are located in this state." As such, RCW 19.405.030(1) prohibits a utility from including the benefits and costs associated with coal power in its retail customer electricity rates after December 31, 2025, other than costs associated with decommissioning and remediation.

95 As CETA requires that PSE remove the benefits and costs of coal power from its retail customer rates as of January 1, 2026, the Commission determines that costs associated with capital investments in Colstrip based on benefits that are realized after 2025 must be excluded from rates. The Commission generally agrees with the non-company parties that this outcome may be achieved by prorating the Company's recovery of costs based on the portion of their useful lives in service prior to the CETA deadline to remove coal power from PSE's allocation of electricity.

96 The Commission disagrees with PSE's argument that the 2017 and 2022 GRC settlements support the Company's request for full recovery of its assets or that proration would be unjust because it contradicts those settlements. Regarding the 2017 GRC settlement, the Commission observes that this settlement was approved prior to the enactment of CETA. Insofar as the 2017 GRC settlement did not contemplate the additional requirements under CETA, the Commission is not persuaded that settlement controls the Commission's analysis in this proceeding. Furthermore, review of the order approving the 2017 GRC settlement indicates that the terms regarding depreciation only apply to those investments that were known at the time of the settlement:

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

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

> Balancing PSE's interest in recovering **all of the net plant amounts remaining on its books for the Colstrip units as of September 30, 2016**, against the Settling Parties' common interest in protecting ratepayers from significant rate impacts and avoiding intergenerational inequities, the Settlement Stipulation establishes two new accounts.
>
> . . .
>
> In the final analysis, we determine that the Settlement Stipulation takes advantage of the unique circumstances in which PSE, without significant rate impacts, is able to recover fully the undepreciated Colstrip plant balances **on the Company's books** on significantly shortened depreciation schedules tied to the known retirement date for Units 1 & 2 and a well-considered change for Units 3 & 4.[234]

As such, as the assets on issue in this proceeding were not "on the Company's books" at the time of the 2017 GRC settlement, the Commission does not interpret that settlement as presently controlling.

97 Turning to the 2022 GRC settlement, while PSE is correct that the record reflects that the settling parties in that case contemplated terminal depreciation,[235] the settlement also expressly provides for additional review of investments related to Colstrip:

> j. <u>Colstrip.</u> PSE will move Colstrip rate base and expense into a separate tracker under Schedule 141-C, as proposed in the testimony of Susan E. Free (Exh. SEF-18). PSE agrees to exclude capital investments associated with the construction of PSE's Colstrip dry ash facilities from recovery in base rates in this case and PSE's proposed Schedule 141-C tracker. **The Settling Parties agree that Colstrip costs included in rates in 2023 and beyond (including major maintenance expense and new plant additions) are subject to review, including but not limited to an examination of prudence, in PSE's annual Schedule 141-C tariff filing.** Major maintenance costs incurred during the MYRP will be amortized over three years, regardless of the year incurred. Costs amortized after 2025 would not be recovered in rates. **The Settling Parties retain all rights to challenge Colstrip costs when PSE files tariff revision for the tracker**.[236]

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[234] *WUTC v. Puget Sound Energy*, Dockets UE-170033 & UG-170034 (*consolidated*), Order 08 at 40, 50-51 ¶¶ 111, 136 (Dec. 5, 2017) (emphasis added, internal citations omitted).

[235] Free, Exh. SEF-1T at 6:1-21; Free, TR. at 115:12 – 116:13.

[236] *WUTC v. Puget Sound Energy*, Dockets UE-220066, UG-220067, & UE-210918 (*consolidated*), Order 24/10, Appendix A at 7-8 ¶ 23 j (Dec. 22, 2022) (emphasis added).

Given that the 2022 GRC settlement clearly preserved the parties' ability to challenge the inclusion of subsequent costs related to Colstrip in a future proceeding, PSE cannot reasonably rely on the 2022 GRC settlement as requiring the inclusion of all Colstrip costs at issue in this proceeding. The 2022 GRC settlement did not preapprove any of the assets that are currently before the Commission for review and does not preclude the Commission from disallowing costs that fail to satisfy applicable legal standards on a prorated basis.

98 The Commission further disagrees with PSE's assertion that prorating its recovery in this case would be unfair and contrary to the Commission's Used and Useful Policy Statement. The Used and Useful Policy Statement states in part that "rates must be fair to both customers and the public service company[.]"[237] Although the Company maintains that it would be unfair to prorate the recovery of its Colstrip investments because it was obligated by its ownership agreement to fund its full share of those assets, that agreement was entered into at the discretion of PSE and PSE's customers had no control over whether to accept those terms. To the extent that PSE argues that it lacks discretion because of the O&O Agreement, that lack of discretion was created by PSE's own actions. The Commission also rejects PSE's argument that Washington customers will receive the full benefit of Colstrip costs associated with capital projects and maintenance regimes that extend past the CETA deadline to remove coal from the allocation of electricity.[238] As the Company stated at hearing, Colstrip provides no benefit to ratepayers after 2025:

> Q: So if you could look at your rebuttal testimony at Page 11, Lines 11 to 13. Actually, 13 to 14. And it indicates that, in response to AWEC's testimony, that as of December 31st, 2025, Colstrip is not necessary or useful in the performance of any PSE duties to the public; is that correct?
>
> A: That is correct.[239]

99 Witness Atwood similarly testified:

> Q: Just to clarify: CETA requires that coal be out of rates effective December 31st, 2025. Is that your understanding?
>
> A: Yes.

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[237] Policy Statement on Property that Becomes Used and Useful After the Rate Effective Date, Docket U-190531 at 14-15 ¶ 43 (Jan. 31, 2020).

[238] Atwood, Exh. NLA-1T at 20:4-6.

[239] Roberts, TR. at 103:23 – 104:4. *See also* Roberts, Exh. RJR-1T at 11:13-14 ("As of December 31, 2025, as AWEC knows, Colstrip is not necessary or useful in the performance of any PSE duties to the public.").

> Q: And so after that date, coal plant will not be used to serve Washington ratepayers; is that correct?
>
> A: It will not be operational to serve customers, PSE customers.
>
> Q: In Washington?
>
> A: Yes.
>
> . . .
>
> Q: Is the Colstrip plant after December 31st, 2025, worth anything to Washington customers?
>
> A: Puget Sound Energy cannot have it in its rates. By getting out of the plant at the end of the required timeline, Washington customers benefit from a cleaner portfolio.
>
> Q: Okay. So there's a benefit. But in terms of the actual output of Colstrip, is there any value to Washington customers after that date?
>
> A: There will not be benefit of operating after that date, no.[240]

100 While the Commission must carefully evaluate the needs of both customers and the Company, the Commission does not find that it would be fair to require Washington customers to bear the full costs of assets from which they will only receive a fraction of the benefits relative to those assets' useful lives. Rather, prorating the assets based on the portion of their useful lives in service prior to the CETA deadline to remove coal power from PSE's allocation of electricity appropriately assigns fair costs to ratepayers relative to the benefit they actually receive from the Colstrip assets.[241]

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[240] Atwood, TR. at 56:7-16, 76:1-12. The Commission notes that while the witness did further respond that "Well, the [Colstrip] power will be on the grid" and that "would potentially be a benefit in some way," this assertion is speculative and conflicts with the witness's earlier statement that Colstrip could not serve Washington customers after 2025. Atwood, TR. at 76:16 – 77:7.

[241] On the issue of fairness, the Commission also notes that the Company was aware of the possibility that certain Colstrip assets may be subject to disallowance as part of this proceeding. *See* Roberts, Exh. RJR-1T at 13:10-12 (explaining that PSE voted no on certain budget items in part because "PSE felt that the possibility of a disallowance by the Commission would leave the Company in a difficult negotiating position with NorthWestern should PSE not have some logic to its No votes.").

i. Human Health and Safety Investments

101 However, the Commission determines that the six human health and safety projects should be fully recovered by PSE because they provide a benefit beyond facilitating the generation of electricity.[242] As testified to by Staff, these projects were intended to address employee health and safety hazards related to Colstrip operations:

> Two of the projects (the Snubber Rebuild and the Hot Reheat Elbow Replacement) address risks associated with damaged or out-of-code high-pressure steam lines where failure of the existing equipment could result in the release of 1000 degree high-pressure steam onto the turbine deck, one of the projects (the switchgear mod) is necessary for code compliance and addresses the risks that plant personnel will be exposed to high-energy arc flash events, and one of the projects (the coal pipe replacement) addresses coal pipe leaks which increase the risks of explosions and create employee health hazards such as an elevated risk of silicosis, pneumonia, and black lung.
> . . .
> The boiler scaffolding provides a safe structural environment during boiler inspections and repairs, and the boiler elevator allows large and heavy equipment to be safely moved to various locations on the boiler.[243]

102 The Commission agrees with Staff's assessment that the "near-term benefits of th[e]se projects exceed the cost of their investment," and determines that they should be fully included in rates.[244] The Company's ratepayers benefit from reasonable human safety investments that reduce the Company's risk of liability in the event of an incident resulting in injury or death to plant workers. Absent such investment, investors may be led to perceive the Company as relatively riskier, which could in turn require a greater degree of compensation to investors to account for that risk, thereby increasing overall future rates to customers.[245] Although utilities must transition away from certain resources to comply with CETA, the Commission does not want to create an incentive for utilities to avoid reasonable safety investments for such resources that place workers in threat of harm,

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[242] Specifically, the six human safety projects are (1) Switchgear modification; (2) the U4 Boiler Snubber rebuild; (3) the Coal Pipe Replacement; (4) the U4 Hot Reheat Elbow Replacement; (5) the U4 Boiler Scaffolding; and (6) the U4 Boiler Elevator. McGuire, Exh. CRM-1T at 9:15-20.

[243] McGuire, Exh. CRM-1T at 10:4-19 (citations omitted). *See also* Cebulko, Exh. BTC-1CT at 26:9 – 27:10 (recommending full recovery of the same six human safety projects).

[244] McGuire, Exh. CRM-1T at 11:2-5.

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

which generally would be contrary to the public interest.[246] The Commission has no desire to see the transformation of Washington's energy supply to clean energy built upon a foundation of unnecessary hazards and risk of harm to workers.

ii. Assets with 2025 In-Service Dates

103 With respect to assets with in-service dates in 2025, the Commission determines that such assets should be prorated consistent with the Commission's used and useful analysis discussed above. Regarding the U4 Generator Exciter and the Northern Cheyenne AAQ System, the Commission finds that PSE should be required, as a condition of compliance with this order, to make a supplemental filing indicating when these two investments were placed into service. If these investments were placed into service on or before December 31, 2025, the Company should be allowed to recover a pro rata portion of these investments for two reasons. First, to the extent that these assets are placed into service on or before the deadline to remove coal from rates, they have provided some benefit to Washington customers that warrants proportional recovery in the interest of fairness. Second, because CETA requires that coal power be removed from PSE's allocation of electricity after 2025, PSE will not have another opportunity to recover these costs in a subsequent proceeding. As such, the Commission exercises its discretion to require PSE to file an update to the record as a condition of compliance with this order due to the requirements of CETA but cautions that this unique situation should not be interpreted as setting a general precedent for future GRCs.

B. Prudence

104 During GRC proceedings, the Commission determines the prudence of utility expenditures by reviewing whether the utility made reasonable business decisions in light of the facts and circumstances known or that reasonably should have been known to the utility at the time decisions were made.[247] What is reasonable requires assessment of choices made, in light of circumstances and possible alternatives, based on industry norms and practices.[248]

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

[247] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12 at 8-9 ¶ 19 (Apr. 7, 2004).

[248] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12 at 8-9 ¶ 19 (Apr. 7, 2004).

Prudence does not require a single, ideal decision, but requires the utility to make a reasonable decision among a number of alternatives that the Commission might find prudent.[249] The prudence review "requires evaluation of the Company's decisions not just from the perspective of management for the benefit of shareholders, but also for the benefit of customers."[250] The fundamental question for decision is whether management acted reasonably in the public interest, not merely in the interest of the company.[251]

105 The prudence standard applies to both the question of need and the appropriateness of the expenditure.[252] The Commission considers three broad questions when evaluating prudence: (1) Was the initiation of the project prudent; (2) Was the continued implementation of the project prudent; and (3) Were the expenses prudently incurred?[253] The second and third factors are examined using the same prudence test as the first factor, but applied at a different point in time and necessarily premised on a reevaluation of the project.[254] Consequently, the Commission's prudency review is not limited to a single point in time and encompasses the implementation and construction phases of a project to ensure that a regulated utility continues to reasonably control and evaluate a project.

106 As noted above, when evaluating prudence, the Commission reviews utility decision-making at the time decisions were made. Stated differently, the Commission will not use the benefit of hindsight when evaluating prudence.[255] Consequently, regulated utilities are required to maintain contemporaneous records of their decision-making process and analysis to satisfy the Commission's prudency standard.[256] A utility's "robust discussions" about a project, with a "consensus" on decisions, is not sufficient to demonstrate

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

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

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

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

[253] *WUTC v. PacifiCorp,* Docket UE-152253, Order 12 at 34 ¶ 95 (Sept. 1, 2016).

[254] *WUTC v. PacifiCorp,* Docket UE-152253, Order 12 at 34 ¶ 95 (Sept. 1, 2016).

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

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

prudence.[257] Rather, "the parties and Commission should be able to follow the company's decision-making process, knowing what elements the company used, and the manner in which the company valued those elements. Such a process should certainly be documented."[258] "Documentation and evidence of prudence decision making must be kept contemporaneously with a company's decision making or the Commission's ability to evaluate prudence is thwarted."[259]

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

> 1) *The Need for the Resource:* The utility must first determine whether new resources are necessary. Once a need has been identified, the utility must determine how to fill that need in a cost-effective manner. When a utility is considering the purchase of a resource, it must evaluate that resource against the standards of what other purchases are available, and against the standard of what it would cost to build the resource itself.
>
> 2) *Evaluation of Alternatives:* The utility must analyze the resource alternatives using current information that adjusts for such factors as end effects, capital costs, dispatchability, transmission costs, and whatever other factors need specific analysis at the time of a purchase decision. The acquisition process should be appropriate.
>
> 3) *Communication With and Involvement of the Company's Board of Directors:* The utility should inform its board of directors about the purchase decision and its costs. The utility should also involve the board in the decision process.
>
> 4) *Adequate Documentation:* The utility must keep adequate contemporaneous records that will allow the Commission to evaluate the Company's decision-making process. The Commission should be able to follow the utility's decision process; understand the elements that the utility used; and determine the manner in which the utility valued these elements.[260]

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

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

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

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

108 As stated above, the Commission has already disallowed the costs associated with Colstrip investment assets' remaining useful lives after 2025 based on those portions of the assets not providing any service or benefit to Washington customers. Consequently, the Commission's prudence review is limited to the remaining portions of those costs.

109 The Commission finds that the Company has sufficiently demonstrated that the remaining portions of the assets and costs it seeks to include in rates are prudent.[261] With regard to the question of need, PSE has made a reasonable showing of the need for the assets based on the analysis prepared by the Colstrip operator and the forecasted costs of replacement power.[262] The Commission is not persuaded that the Company's decision to vote "no" on certain capital investments is evidence of a lack of need, as the Company's voting strategy can be informed by several considerations, including CETA compliance and prior Commission orders.[263] The Commission also disagrees that investments that extend the life of Colstrip are categorically prohibited under the prudence standard. Both Staff and NWEC cite to the Commission's order in Avista's 2020 GRC to support their argument that investments that extend the life of Colstrip must be excluded from the Company's rates.[264] However, the Commission's consideration of whether the Dry Ash Disposal project was life extending was a product of Avista's settlement obligations from a prior GRC, not a component of the Commission's general prudence standard.[265]

110 The Commission also rejects the premise that the prudence standard requires a specific form of cost-benefit analysis. While a utility must include some form of analysis as part of its demonstration of need and consideration of alternatives, the Commission does not require a particular type of analysis under the general prudence standard, leaving the utility with discretion to develop a cost analysis that is reasonable under the circumstances. The Commission finds that the discussion of the prudence of Avista's advanced metering infrastructure investment in the first Avista 2015 GRC order is distinguishable, as in that

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[261] The Commission declines AWEC's invitation to articulate a prudence standard regarding all investments that extend the life of fossil fuel resources that departs from its longstanding prudence framework. The Commission is not persuaded that a modification of its well-established standard is necessary or warranted.

[262] Atwood, Exh. NLA-7C.

[263] Roberts, Exh. RJR-1T at 13:10-12.

[264] Brief of Staff at 10 ¶ 23; Brief of NWEC at 6 ¶ 15.

[265] *WUTC v. Avista Corp.*, Dockets UE-200900, UG-200901, & UE-200894 (*consolidated*), Order 08/05 at 100 ¶ 279 (Sept. 27, 2021) ("Lastly, we are uncertain that Dry Ash is not a life-extending capital addition. Our 2019 Avista GRC Final Order approved a settlement that included an agreement by Avista not to support capital expenditures beyond routine capital maintenance costs that would extend Colstrip's operational life beyond December 31, 2025.").

case Avista had not yet implemented its AMI program and the prudence of AMI was not sufficiently ripe for adjudication.[266] However, the first Avista 2015 GRC order does highlight the fact that, while the Commission will not "preapprove" a particular type of analysis to support prudence, a utility risks a disallowance if it presents an analysis that has insufficient detail or otherwise lacks credibility.[267] Additionally, the Commission's discussion in PacifiCorp's 2005 GRC regarding the demonstration of "tangible and quantifiable benefits to Washington of resources in the system," was in the context of reviewing PacifiCorp's interjurisdictional allocation methodology, rather than as part of a prudence review.[268]

111 However, the Commission agrees that the O&O Agreement does not independently satisfy the required showing of need under the prudence standard. While the O&O Agreement creates an obligation for PSE to pay for its proportional share of budget items that are approved by the Colstrip owners, the owners' approval is not determinative of whether a utility has demonstrated a reasonable need. If the fact that PSE is required to fund its portion of investments pursuant to a contract were all that is necessary to demonstrate need, the need would be met for every Colstrip asset approved, which would effectively nullify the Commission's prudency review. Furthermore, the Commission has previously disallowed Colstrip assets that the owners voted to approve based on a finding of lack of need, such as the Commission's previous SmartBurn disallowance, which further supports a determination that the O&O Agreement's obligation to pay does not, by itself, satisfy the need component of the prudence standard.[269]

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[266] *WUTC v. Avista Corp*, Dockets UE-150204 & UG-150205 (*consolidated*), Order 05 at 71 ¶ 199 (Jan. 6, 2016)("In conclusion, we decline to rule on the prudency of Avista's proposed AMI investment in this case because the issue is not ripe for our determination. This decision should not be interpreted as a rejection of AMI. The Company must decide what metering program provides ratepayers the most benefit at the least cost.").

[267] *WUTC v. Avista Corp*, Dockets UE-150204 & UG-150205 (*consolidated*), Order 05 at 69 ¶ 193 (Jan. 6, 2016) ("While we do not make a decision regarding the prudence of this project in this proceeding, we note the considerable uncertainty surrounding the business case analysis Avista prepared. . . . We look forward to a more refined cost-benefit analysis in a future proceeding, including a fuller discussion of "non-quantifiable benefits" suggested by Mr. Kopzcynski.").

[268] *WUTC v. PacifiCorp*, Dockets UE-050684 & UE-050412 (*consolidated*), Order 04/03 at 27-28 ¶ 68 (Apr. 27, 2006).

[269] *WUTC v. Avista Corp.*, Dockets UE-200900, UG-200901, & UE-200894 (*consolidated*), Order 08/05 at 98 ¶ 274 (Sept. 27, 2021) (disallowing SmartBurn investment in Colstrip because the utility "failed to demonstrate that SmartBurn was necessary and failed to produce documentation sufficient to demonstrate that its costs were prudently incurred.").

112 Turning to the NPV analysis supporting PSE's Colstrip costs in this case, the Commission agrees with the non-company parties that the analysis is questionable in some respects. Although the Commission agrees that PSE's failure to fund an approved capital investment will result in default under the O&O Agreement, the record does not indicate that Talen's decision to assume 100 percent probability of failure was intended to reflect a shareholder's default.[270] However, while the persuasiveness of the NPV analysis is weakened by the fact that the analysis is not risk adjusted, the Commission is not persuaded that this condition makes the analysis wholly unreliable.

113 Additionally, in light of the Commission's above analysis excluding the portions of Colstrip investments not used and useful in Washington after 2025, the Commission finds that the NPV analysis is sufficiently reasonable even though it is not performed from the perspective of Washington ratepayers. While the Commission will not proscribe the type of analysis that a utility may utilize to support its showing of prudence, if such analysis is based on general rather than Washington-specific data, the utility should be able to explain how that data supports prudence from the perspective of Washington ratepayers. In some cases, there may be no distinction between the general benefit and the Washington specific benefit, insofar as the Washington benefit is a proportional share of the general benefit. But, in circumstances where the Washington benefit may materially diverge from the general benefit, such as when a resource may no longer be used to provide service in Washington, further analysis should be performed to verify that the investment is still prudent with respect to Washington ratepayers.

114 Based on the above discussion, the Commission finds that the Company has demonstrated a need for the prorated portions of the Colstrip assets in this case based on the NPV analysis and forecasted replacement power costs.[271] The same evidence also supports a finding that the Company considered alternatives to continuing to fund Colstrip and that it documented its reasoning contemporaneously. The record also demonstrates that the Company informed and consulted with its management about the investment decisions related to Colstrip.[272]

115 As to the equity considerations raised by Public Counsel regarding PSE's full inclusion of Colstrip costs, the Commission has addressed this issue by prorating PSE's recovery of

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[270] Atwood, Exh. NLA-7C; Exh. NLA-9.

[271] Atwood, Exh. NLA-7C.

[272] Atwood, Exh. NLA-1T at 20:8-17; De Villiers, Exh. SDV-3C, Attach. A.

Colstrip costs.[273] Prorating PSE's recovery of investments in Colstrip promotes equity by appropriately assigning costs to Washington customers relative to the benefits that they will receive before coal-fired resources can no longer be included in PSE's allocation of electricity. The Commission's analysis in this matter is also informed by the numerous public comments filed in this docket raising concerns about affordability and opposing continued support for coal-fired resource operations past 2025 despite CETA's mandate to remove coal from the allocation of electricity.[274]

i. SmartBurn

116 In this docket, PSE is seeking recovery for costs associated with four components of the NOx control system:

- Unit 4 Boiler Burner AuxAir Replacement (Boiler Burner)
- Unit 4 Separated Over Fire Air Bucket Replacement (SOFA)
- Unit 4 Top Over Fire Air Bucket Replacement (TOFA)
- Control Room Operator (CRO)[275]

117 Although the Commission finds general prudence in PSE's Colstrip investments, the Commission finds that specific Company investments labelled "SmartBurn" were not prudently incurred because the Company did not demonstrate that the investments were necessary, based on the Commission's prior disallowance of certain SmartBurn investments.[276]

118 In PSE's 2019 GRC, the Commission disallowed recovery of investments in SmartBurn technology that is associated with the NOx Combustion Control system after the Commission found that "PSE failed to demonstrate that the costs related to PSE's

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[273] Brief of Public Counsel at 20-22 ¶¶ 61-68; *WUTC v. Cascade Natural Gas Corp.*, Docket UG-210755, Order 09 at 19-20 ¶ 59 (Aug. 23, 2022) (retaining discretion to evaluate equity on a case-by-case basis). However, the Commission declines to consider the articles cited by Public Counsel in its briefing, as those articles are not part of the record in this case, and Public Counsel has not motioned for the Commission to take official notice of those articles or explained why they could not have been previously submitted to the record.

[274] *See generally* BR 5, Public Comment Exhibit.

[275] Atwood, Exh NLA-11T at 4:12-19, 7:3-12.

[276] *WUTC v. Puget Sound Energy*, Dockets UE-190529, UG-190530 (consolidated), UE-190274, UG-190275 (*consolidated*), UE-171225, UG-171226 (Consolidated), UE-190991 & UG-190992 (*consolidated*), Order 08/05/03 at 61 ¶ 197 (Jul. 8, 2020).

SmartBurn investment were prudently incurred[,]"[277] In particular, the Commission found that PSE failed to demonstrate that SmartBurn was necessary and "failed to maintain appropriate documentation of its decision to install SmartBurn."[278] During the initial rounds of testimony in this docket, the parties were not clear on what components of the NOx control system were related to the SmartBurn investments the Commission previously disallowed in PSE's 2019 GRC. In response to DR 19 from NWEC, the Company identified the Boiler Burner, SOFA, and TOFA as SmartBurn technology.[279] However, PSE clarified that the only component of the NOx control system that had been previously disallowed was the TOFA component.[280] The Company confirms that the Boiler Burner and SOFA investments on Units 3 and 4 were installed prior to 2016 and were not part of the 2019 GRC.[281]

119 Because PSE's investment in the SmartBurn TOFA component of the NOx control system has been previously disallowed as imprudent, we analyze PSE's request for recovery for investment in replacing the TOFA component for prudence. The Company has argued that although the Commission disallowed recovery of its investment in the TOFA component in the 2019 GRC, that should not influence the Commission's decision in this matter, and the Commission should only look to the record in this docket and not a previous docket to determine prudence.

120 In determining whether an investment was prudently incurred, we consider what the Company knew at the time it made the investment. The Company was aware that the Commission had previously found its costs related to investment in SmartBurn/TOFA to be imprudently incurred at the time it invested in the replacement component.[282] We can understand the Company's concerns that that the TOFA component is an integrated part of the NOx control system and that the TOFA replacement was necessary because the plant

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[277] *WUTC v. Puget Sound Energy*, Dockets UE-190529, UG-190530 (*consolidated*), UE-190274, UG-190275 (*consolidated*), UE-171225, UG-171226 (*consolidated*), UE-190991 & UG-190992 (*consolidated*), Order 08/05/03 at 61 ¶ 197 (Jul. 8, 2020).

[278] *WUTC v. Puget Sound Energy*, Dockets UE-190529, UG-190530 (consolidated), UE-190274, UG-190275 (*consolidated*), UE-171225, UG-171226 (Consolidated), UE-190991 & UG-190992 (*consolidated*), Order 08/05/03 at 61 ¶ 197 (Jul. 8, 2020).

[279] Cebulko, Exh. BTC-6.

[280] PSE's Response to BR 2 at 2 (September 10, 2025); PSE's Revised Response to BR 6 at 1 (October 30, 2025).

[281] PSE's Response to BR 5 at 2 (October 27, 2025).

[282] *See WUTC v. Puget Sound Energy*, Dockets UE-190529, UG-190530 (*consolidated*), UE-190274, UG-190275 (*consolidated*), UE-171225, UG-171226 (*consolidated*), UE-190991 & UG-190992 (*consolidated*), Order 08/05/03 at 61 ¶¶ 197-199 (Jul. 8, 2020).

cannot run without it. However, the Company has not provided additional documentation to demonstrate prudence in its TOFA investment, thus there is not sufficient information in the record to persuade us that the Company's investment was prudently incurred. Because the Company's investment in relation to the SmartBurn TOFA component is not prudent, we find that the Commission should disallow cost recovery related to the TOFA component.

121 The Company clarified that the CRO, Boiler Burner, and SOFA components were installed in the NOx control system prior to its 2019 GRC and were not subject to the decision in that order. Further, the Company has conceded that the TOFA component was disallowed as imprudent.[283]

122 We find the installation timeline of the SOFA component provided by the Company sufficiently rebuts NWEC's argument because it demonstrates that SOFA was installed on Colstrip Units 3 and 4 in 2007 and 2009 respectively, and was not subject to the 2019 GRC decision.[284] Because the Boiler Burner, CRO, and SOFA components of the NOx control system were not subject to PSE's 2019 GRC, we do not find that recovery on investment for these components was disallowed in PSE's 2019 GRC. The Boiler Burner, CRO and SOFA are not subject to the same analysis as the TOFA component but are subject to the Commission's pro-rata analysis in the Used and Useful section of this order above.

ii. *Assets Lacking Capital Justification*

123 The Commission further determines that PSE has not demonstrated the prudence of four investments that lack capital justification.[285] As noted by NWEC, the Company has stated in both testimony and in response to discovery that there are no capital justifications for four projects, and those projects are not discussed in the Company's NPV analysis.[286] As such, the Commission determines that the Company has not demonstrated the need for these investments or provided contemporaneous documentation with respect to its decision to pursue these investments, and has not demonstrated that they are prudent.

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[283] Brief of PSE at 18-19 ¶ 32.

[284] PSE's Response to BR 2.

[285] Cebulko, Exh. BTC-1CT at 26:1-2 (identifying projects lacking capital justification as (1) Boiler Feed Pump Rebuild-Element; (2) PA Fan Motor Rewind/Refurb; (3) Boiler Feed Booster Pump RB; and (4) Motor Circ Wtr Pump Cap Spare).

[286] Cebulko, Exh. BTC-1CT at 25:13-18 (*citing* Atwood, Exh. NLA-1T at 11:1, fn. 17); Cebulko, Exh. BTC-7 at 1 (stating for each of the four projects "No Capital Justification available, inspection based work after removal.").

V. Operations & Maintenance Amortization

124 Staff contests a portion of PSE's major maintenance amortization expenses related to the 2024 Unit 4 outage. Staff explains that PSE has included a total major maintenance amortization expense of $4,201,653 related to four separate Colstrip outages, with the 2024 Unit 4 outage accounting for $1,609,006.[287] Staff contends that dividing the total 2024 Unit 4 outage cost of $4,471,694 by 36-months should result in a monthly amortization expense of $124,214, but PSE has included a monthly amortization expense of $134,048 in its filing.[288] Based on a monthly amortization cost of $124,214, Staff maintains that the annual amortization associated with the 2024 Unit 4 outage should be $1,490,565.[289] Staff recommends that the Commission reduce the annual major maintenance amortization expense included in rates from $1,609,006 to $1,490,565.[290]

125 PSE maintains that while Staff's methodology for calculating the annual amortization expense is correct, it is based on an incorrect total event cost for the 2024 Unit 4 outage.[291] The Company asserts that $4,471,694 included in its original filing was based on a preliminary amount rather than the final amount, and that the correct costs associated with the 2024 Unit 4 outage is $4,809,523.[292] Based on the correct amount, PSE argues that the correct total amortization for the 2024 Unit 4 outage is $1,603,174.[293]

Commission Determination

126 The Commission agrees with PSE's updated calculation of the annual amortization expense associated with the 2024 Unit 4 outage. PSE's updated calculation on rebuttal is based on the actual cost of the 2024 Unit 4 outage, rather than the preliminary estimate that was included in the Company's initial filing. As such, the amount associated with the annual amortization associated with the 2024 Unit 4 outage should be corrected from $1,609,006 to $1,603,174. The Commission further determines that major maintenance operations and

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[287] McGuire, Exh. CRM-1T at 36:11-18.

[288] McGuire, Exh. CRM-1T at 37:10-16.

[289] McGuire, Exh. CRM-1T at 37:17-20.

[290] McGuire, Exh. CRM-1T at 37:22 – 38:4.

[291] Free, Exh. SEF-1T at 11:1-4.

[292] Free, Exh. SEF-1T at 11:4-10.

[293] Free, Exh. SEF-1T at 11:11 – 12:2.

maintenance expenses should be recovered consistent with the terms of PSE's 2022 GRC settlement.[294]

VI. Refund Process

127 Although PSE maintains that no refund is necessary, if the Commission does require a refund, the Company recommends that the Commission require the Company to either provide a refund directly to customers or apply the refund against PTCs.[295] PSE raises concerns that CETA's requirement to remove coal from its allocation of electricity after 2025 could be interpreted to prohibit a direct refund to customers through Schedule 141COL.[296] If the Commission determines that a direct refund is not permitted under CETA, the Company recommends applying the refund against its PTCs and states that customers would still be compensated for the time value of money because they would offset rate base in the Colstrip Tracker.[297]

128 Staff recommends that the Commission require the Company to directly refund any over collected amounts through PSE's Schedule 141COL beginning in 2026.[298] Specifically, Staff argues that the Commission should require PSE to refund over-collected amounts after 2024 plant additions are trued up to actuals, as PSE's original filing did not have actual costs for all of the 2024 projects.[299] Staff further asserts that the Commission should maintain currently effective rates through 2025 and order PSE to refund trued-up over-collected amounts over the course of 2026 through Schedule 141COL.[300] Staff contends that requiring PSE to file compliance tariff revisions to Schedule 141COL, with an effective date of Jan. 1, 2026 and containing trued-up 2024 plant amounts, would simplify the refund calculation, allow the trued-up amounts to be reflected in the refund, and reduce the number of tariff revisions required by PSE.[301]

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[294] *WUTC v. Puget Sound Energy*, Dockets UE-220066, UG-220067, & UE-210918 (*consolidated*), Order 24/10, Appendix A at 7-8 ¶ 23 j (Dec. 22, 2022) (stating in part "Major Maintenance costs incurred during the MYRP will be amortized over three years, regardless of the year incurred. Costs amortized after 2025 would not be recovered in rates.").

[295] Brief of PSE at 23 ¶¶ 40-41; Free, Exh. SEF-1T at 14:2 – 15:16.

[296] Free, Exh. SEF-1T at 14:6-17.

[297] Brief of PSE at 23 ¶ 41; Free, Exh. SEF-1T at 15:1-16.

[298] Brief of Staff at 19-20 ¶ 39; McGuire, Exh. CRM-1T at 39:19 – 40:5.

[299] McGuire, Exh. CRM-1T at 29:13-19; 39:3-17.

[300] McGuire, Exh. CRM-1T at 39:19 – 40:8.

[301] McGuire, Exh. CRM-1T at 31:12 – 32:4.

129 Public Counsel maintains that the Commission should require PSE to directly refund any over collected amounts either through a one-time bill credit or over a period not to exceed one year.[302] Public Counsel states that a direct refund is more appropriate than waiting to apply any refund against future decommissioning and remediation expenses because customers benefit more from a direct refund due to the time value of money.[303]

130 NWEC recommends that the Commission require PSE to refund over collected amounts directly to customers rather than apply that refund against PTCs.[304] While AWEC recommends that the Commission disallow various costs PSE included in its filing, it does not provide a recommendation regarding the mechanism for refunding the disallowance.[305]

Commission Determination

131 The Commission requires PSE to directly refund over collected amounts to customers consistent with the method identified by Staff, rather than apply those costs against future PTCs. Staff's proposed method is administratively efficient and will provide more immediate relief to PSE's customers, which is in the public interest and promotes equity. While the Commission appreciates PSE's concern regarding whether a refund complies with CETA's requirement to remove coal power from the allocation of electricity, the Commission does not interpret RCW 19.405.030(1) to prohibit a refund under these circumstances. When the Commission authorized rates to go into effect in this proceeding, it did so subject to refund based on further development of the record and adjudication.[306] As such, the refund required in this case represents an adjustment to rates that were in effect from the end of 2024 to the end of 2025, when the costs and benefits associated with coal power could still be included in rates.

VII. 2025 Colstrip Plant Filing

132 Staff recommends that the Commission clarify the anticipated process for review of PSE's offsetting of 2025 Colstrip plant additions against PTCs. Staff further suggests that the annual Schedule 141COL tariff revision docket filing on or before September 30, 2026, would be a reasonable venue to review PSE's use of PTCs and potentially contesting

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[302] Brief of Public Counsel at 24-25 ¶ 76.

[303] Brief of Public Counsel at 24-25 ¶¶ 74-76; Dreyer, Exh. JMD-1CTr at 8:15 – 9:3.

[304] Cebulko, Exh. BTC-1CT at 3:12-13.

[305] Brief of AWEC at 10 ¶ 20.

[306] *WUTC v. Puget Sound Energy*, Docket UE-240729, Order 01 at 3 ¶ 9 (Dec. 23, 2024).

certain plant additions.[307] AWEC similarly argues that the Commission should require PSE to submit a filing regarding the Company's final regulatory accounting for Colstrip as of December 31, 2025, that will involve a prudence determination for plant balances that the Company proposes to offset with PTCs.[308] AWEC also asks that the Commission clarify that the same principles that apply to the Commission's review in this case will apply to the Commission's review of PSE's 2025 Colstrip plant additions.[309] Public Counsel also indicates that it supports AWEC's recommendation that the Commission evaluate the prudency of the Company's 2025 Colstrip plant additions to be applied against PTCs.[310] PSE states that it agrees with Staff's proposal regarding the treatment of 2025 plant requirements in PSE's annual Schedule 141COL filings.[311]

Commission Determination

133 The Commission agrees that it is appropriate to provide further guidance regarding the review of 2025 Colstrip plant additions and agrees with Staff's recommended process. The Commission requires PSE to file as part of its annual Schedule 141COL filing on or before September 30, 2026, its final proposed regulatory accounting for Colstrip costs as of December 31, 2025. As part of this filing, all interested parties and the Commission will have an opportunity to review whether such costs should be offset by PTCs. While the Commission does not prejudge any issues that may arise in the context of reviewing PSE's 2025 Colstrip investments, this Order should be understood as guidance with respect to the Commission's review in that proceeding.

FINDINGS OF FACT

134 Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the parties and the reasons therefore, the Commission now makes and enters the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

135 (1) The Commission is an agency of the state of Washington vested by statute with the authority to regulate rates, regulations, practices, accounts, securities, transfers

[307] McGuire, Exh. CRM-1T at 34:13 – 36:7.

[308] Brief of AWEC at 9 ¶ 19; Mullins, Exh. BGM-1T at 12:11-20.

[309] Brief of AWEC at 10 ¶ 20.

[310] Brief of Public Counsel at 25-26 ¶ 78; Dreyer, Exh. JMD-2CT at 7:2-8.

[311] Free, Exh. SEF-1T at 16:2-5.

of property and affiliated interests of public service companies, including electric and companies.

136 (2) PSE is a "public service company," and an "electrical company," as those terms are defined in RCW 80.04.010 and used in Title 80 RCW. PSE provides electric utility service to customers in Washington.

137 (3) On September 30, 2024, PSE filed with the Commission a proposed revision to rates under the established Colstrip Adjustment Rider Schedule 141COL.

138 (4) PSE requested an annual revenue increase of $4.1 million, or 0.14 percent, which for the typical residential customer using 800kWh per month would be a rate increase of $.18 or 0.16 percent.

139 (5) On December 19, 2024, the Commission entered Order 01 Complaint and Order Allowing Rates Subject to Later Review and Refund; Setting Matter for Adjudication in this docket, requiring PSE to file revised tariff pages no later than December 23, 2024, with an effective date of January 1, 2025, indicating that the increased rates are subject to refund. The Company was directed by Order 01 to file revised tariff pages, which the Company complied with on December 20, 2024.

140 (6) On September 3, 2025, the Commission convened a hybrid evidentiary hearing before the Commissioners that was presided over by ALJ's Harry Fukano and Jessica Kruszewski.

141 (7) Colstrip Units 3 and 4 are coal-fired generating units.

142 (8) At 12:00 a.m. on January 1, 2026, Pacific Standard Time, PSE's ownership interest will transfer to NorthWestern and costs associated with coal-fired generation of electricity will be removed from rates for electricity for PSE's Washington State customers.

143 (9) As of January 1, 2026, Colstrip will provide no benefit to Washington electric retail customers.

144 (10) As of January 1, 2026, Colstrip will not be necessary or useful in PSE's provision of electric service to Washington customers.

145 (11) Six Colstrip projects related to human health and safety provide near-term, immediate benefits that exceed the cost of investment. Those six projects are: (1)

Switchgear modification; (2) the U4 Boiler Snubber rebuild; (3) the Coal Pipe Replacement; (4) the U4 Hot Reheat Elbow Replacement; (5) the U4 Boiler Scaffolding; and (6) the U4 Boiler Elevator.

146 (12) PSE has not demonstrated that its remaining investments in Colstrip, other than the six human health and safety projects previously identified, provide any benefits to Washington customers after December 31, 2025.

147 (13) The record developed in this proceeding does not indicate when the U4 Generator Exciter and the Northern Chyanne AAQ System were placed into service.

148 (14) PSE has not demonstrated a need for four projects that lack capital justification. Those four projects are: (1) Boiler Feed Pump Rebuild-Element; (2) PA Fan Motor Rewind/Refurb; (3) Boiler Feed Booster Pump RB; and (4) Motor Circ Wtr Pump Cap Spare.

149 (15) PSE's costs for capital improvements to the SmartBurn TOFA component of Colstrip Units 3 and 4 were not prudently incurred because the Company was aware at the time it made the decision to replace the TOFA components, that the Commission had previously found PSE's investment in the TOFA component for Colstrip Units 3 and 4 imprudent. Because PSE's investment in the TOFA components in this docket were not prudently incurred, recovery of costs associated with TOFA components are disallowed.

150 (16) The Boiler Burner, CRO, and SOFA are not SmartBurn components that were previously disallowed in PSE's 2019 GRC.

151 (17) The NPV analysis provided by PSE demonstrates a reasonable need for PSE's Colstrip investments, other than the four projects lacking capital justification and the SmartBurn TOFA component, up to December 31, 2025, after which the assets cannot provide any benefit to Washington customers.

152 (18) For its remaining Colstrip investments and costs, PSE has provided sufficient evidence demonstrating that it considered alternatives to its Colstrip investments and costs, consulted with its management, and contemporaneously documented its analysis.

153 (19) PSE's annual amortization of the 2024 Colstrip Unit 4 outage is $1,603,174, rather than $1,609,006, based on its updated actual costs associated with the outage.

154 (20) PSE's annual amortization cost associated with the 2024 Colstrip Unit 4 outage should be adjusted to $1,603,174.

155 (21) Based on the analysis in this proceeding, PSE has over-collected $6,843,705 that should be refunded to its customers, subject to the true up required by this Order. The computation of the over-collected amounts is attached to this Order as Appendix A (Confidential).[312]

156 (22) Staff's recommended process for implementing a refund of over-collected amounts, as described in Exh. CRM-1T at 39:1 – 40:8 is reasonable and not contrary to CETA.

157 (23) Staff's recommended process for reviewing PSE's 2025 Colstrip investments is reasonable.

CONCLUSIONS OF LAW

158 Having discussed above all matters material to this decision, and having stated the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

159 (1) The Commission has jurisdiction over the subject matter of, and Parties to, this proceeding.

160 (2) PSE is an electric company and a public service company subject to Commission jurisdiction.

161 (3) PSE bears the burden to demonstrate that its provisional rates subject to refund are fair, just, reasonable, and sufficient. The Commission's determination of whether the Company has carried its burden is adjudged based on the full evidentiary record.

162 (4) PSE has not demonstrated that the rates allowed to go into effect January 1, 2025, subject to refund, are fair, just, reasonable, and sufficient.

163 (5) Colstrip Units 3 and 4 are coal-fired resources as that term is defined in RCW 19.405.020(7)(a).

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[312] Appendix A (Confidential) shall be provided to PSE and parties that have signed the protective order agreement and shall be posted to the docket.

164 (6) After a careful analysis of the canons of Legislative intent, we find that the Legislature intended for a broad definition of the terms "retired" and "retirement" in RCW 19.405.030(3), which includes the accounting definition.

165 (7) We adopt the Generally Accepted Accounting Principles and Washington State Auditor's definitions of the terms "retired" and "retirement" in the application of RCW 19.405.030(3) in this docket.

166 (8) The provisions of CETA apply to the proceedings in this docket because we find that the Company will have retired Colstrip Units 3 and 4 pursuant to RCW 19.405.030(3) by 12:00 a.m. January 1, 2026.

167 (9) The A&A Agreement between PSE and NorthWestern is not subject to Commission approval under RCW 80.12.020 because, pursuant to RCW 19.405.030(1)(a)'s requirement that coal-fired resources be removed from PSE's allocation of electricity on or before December 31, 2025, Colstrip Units 3 and 4 cannot provide any benefit to PSE's Washington customers.

168 (10) The Commission should reject the request to have PSE file the A&A Agreement for Commission approval pursuant to RCW 80.12.020.

169 (11) The Commission should require PSE, as a condition of this order, to comply with the condition for review of future agreements transferring assets for the purpose of complying with a requirement of CETA, as described in paragraph 55.

170 (12) The six human health and safety investments in Colstrip are fully used and useful. The six projects are: (1) Switchgear modification; (2) the U4 Boiler Snubber rebuild; (3) the Coal Pipe Replacement; (4) the U4 Hot Reheat Elbow Replacement; (5) the U4 Boiler Scaffolding; and (6) the U4 Boiler Elevator.

171 (13) PSE has not demonstrated that its remaining capital investments in Colstrip are used and useful for service in Washington after December 31, 2025.

172 (14) The Commission should disallow a prorated portion of the Colstrip capital investments based on the portion of the investment's useful lives in service prior to December 31, 2025.

173 (15) PSE should be required to file an update to this docket detailing when the U4 Generator Exciter and the Northern Cheyenne AAQ System were placed into

service, including supporting documentation. If either asset was placed into service prior to December 31, 2025, PSE should be allowed to recovery a prorated portion of the costs associated with those investments, consistent with the proration methodology described in paragraph 95.

174 (16) PSE has not demonstrated that its investments in four projects that lack capital justification were prudent. Those four projects are: (1) Boiler Feed Pump Rebuild-Element; (2) PA Fan Motor Rewind/Refurb; (3) Boiler Feed Booster Pump RB; and (4) Motor Circ Wtr Pump Cap Spare.

175 (17) The TOFA component of the NOx control system is a SmartBurn component that was previously disallowed in PSE's 2019 GRC and therefore is imprudent.

176 (18) PSE's remaining investments and costs related to Colstrip that are not disallowed as not used and useful are prudent.

177 (19) PSE should be required to refund over-collected revenue through Schedule 141COL starting Jan. 1, 2026, consistent with Staff's recommended process as described in Exh. CRM-1T at 39:1 – 40:8.

178 (20) PSE should be required to file its final regulatory account for all Colstrip costs as of December 31, 2025, as part of its Schedule 141COL annual filing on or before September 30, 2026, consistent with the guidance in this Order. As part of such filing, other interested parties shall have the ability to review and contest PSE's investments.

ORDER

THE COMMISSION ORDERS:

179 (1) Puget Sound Energy's tariff revisions filed on September 30, 2024, further revised on December 20, 2024, and allowed to go provisionally into effect on January 1, 2025, by prior Commission order, are rejected and subject to refund with respect to the over-collected amounts.

180 (2) Puget Sound Energy is authorized and required to make compliance filings in this docket including all tariff sheets that are necessary and sufficient to effectuate the terms of this Order. PSE should file its compliance tariffs with an effective date of January 1, 2026, on or before December 24, 2025.

181 (3) As a condition of this order, Puget Sound Energy is required to comply with the condition for review of future agreements transferring assets for the purpose of complying with a requirement of CETA, as described in paragraph 55.

182 (4) As a condition of compliance with this order, Puget Sound Energy is required to submit an update to this docket indicating when the U4 Generator Exciter and the Northern Cheyenne AAQ System were placed into service, with supporting documentation, and the record should be reopened for the limited purpose of incorporating this information. If the assets were placed into service prior to December 31, 2025, Puget Sound Energy is authorized to recover a prorated portion of the value of those assets, consistent with the methodology described in paragraph 95.

183 (5) Puget Sound Energy is required to refund over-collection amounts consistent with the methodology described by Staff in Exh. CRM-1T at 39:1 – 40:8.

184 (6) Puget Sound Energy is required to file its final regulatory account for all Colstrip costs as of December 31, 2025, as part of its Schedule 141COL annual filing on or before September 30, 2026, consistent with the guidance in this Order. As part of such filing, other interested parties shall have the ability to review and contest PSE's investments.

185 (7) The Commission Secretary is authorized to accept by letter, with copies to all Parties to this proceeding, filings that comply with the requirements of this Order.

186 (8) The Commission retains jurisdiction to effectuate the terms of this Order.

Dated at Lacey, Washington, and effective December 19, 2025.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

BRIAN J. RYBARIK, Chair

ANN E. RENDAHL, Commissioner

MILTON H. DOUMIT, Commissioner

NOTICE TO PARTIES: This is a final order of the Commission. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 or RCW 81.04.200 and WAC 480-07-870.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-58:
EPA CEMS Data 2021-2025

State	Facility Na	Facility ID	Year	Gross Load	Steam Loa	SO2 Mass (	CO2 Mass	NOx Mass (	Heat Input
WA	Centralia	3845	2021	3338498		794.285	3808194	3237.726	36310042
WA	Centralia	3845	2022	3800396		1261.793	4321275	3650.313	41199918
WA	Centralia	3845	2023	4436385		1161.237	4960494	4107.822	47296887
WA	Centralia	3845	2024	3039265		934.718	3510596	2804.53	33472505
WA	Centralia	3845	2025	2449289		683.202	2279285	1981.104	21732302

(mmBtu)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-59:
NERC 2025-26 Winter Assessment

2025–2026 Winter Reliability Assessment

November 2025

Table of Contents

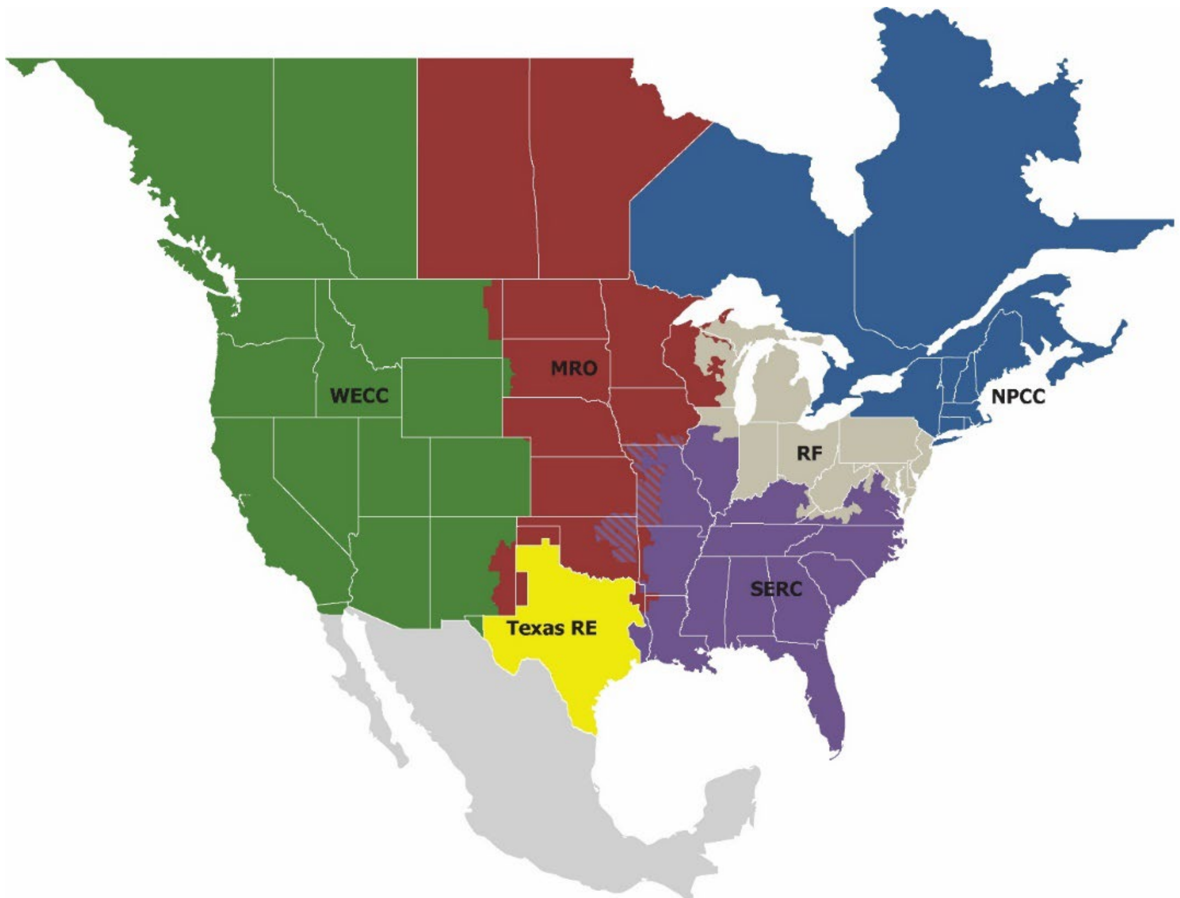
Preface

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

Reliability | Resilience | Security

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

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



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

About this Assessment

NERC's *2025–2026 Winter Reliability Assessment* (WRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the WRA presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS.

The reliability assessment process is a coordinated evaluation between the Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas.

This report reflects an independent assessment by the ERO Enterprise (i.e., NERC and the six Regional Entities) and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming winter period.

Key Findings

This WRA covers the upcoming three-month (December–February) winter period, providing an evaluation of the generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional risks. The following findings are the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as the potential operational concerns that may need to be addressed for the upcoming winter.

Two trends affecting resource adequacy across the BPS for the upcoming winter are rising electricity demand forecasts and a continued shift in the resource mix characterized by the retirement of thermal generators and growth in battery resources. After years of flat or low (~1%) peak demand growth, the aggregate peak demand for all NERC assessment areas has risen by 20 GW (2.5%) since the previous winter. Nearly all assessment areas are reporting year-on-year demand growth; some are forecasting increases near 10%. Total BPS resources have also increased since last winter, but by a smaller amount of 9.4 GW. This number includes the net change in generating capacity as well as additional demand response. These demand and resource changes are described in **Escalating Winter Demand** and **Resource Trends** sections.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operating concerns that should receive attention for Winter 2025–2026:

1. **All areas are assessed as having adequate resources for normal winter peak-load conditions (i.e., the area's 50-50 peak forecast). However, more extreme winter conditions extending over a wide area could result in electricity supply shortfalls.** Prolonged, wide-area cold snaps can drive sharp increases in electricity demand and threaten reliable BPS generation and the availability of fuel supplies for natural-gas-fired generation. Four severe arctic storms have descended to cover much of North America since 2021, causing regional demand for electricity and heating fuel to soar and exposing generation and fuel infrastructure in temperate areas to freezing conditions.[1] The following areas face risks of electricity supply shortfalls during periods of more extreme conditions this winter (see **Figure 1**):
   - **NPCC-Maritimes**: The peak demand forecast has fallen slightly (-1.6%) in the NPCC-Maritimes assessment area, contributing to higher reserves compared to the 2024–2025 winter. Maritimes is projected to have an Anticipated Reserve Margin (ARM) of 16.9%, which is 270 MW below the area's Reference Margin Level of 20% . New Brunswick has long-term energy contracts that can be used to mitigate resource adequacy challenges through the purchase of energy on a day-ahead basis. NPCC's all-hours probabilistic assessment for the NPCC Region included the simulation of both a base case (i.e., normal 50/50 demand) and highest peak load scenario (having an approximate 7% chance of occurring), for both an expected and a low-likelihood, reduced-resource condition. The preliminary results of this assessment indicate that operators in Maritimes are likely to require emergency operating mitigations and/or energy emergency alerts (EEA) during above-normal demand or low-resource output conditions.
   - **NPCC-New England**: A lower peak demand forecast and additional resources from demand response and firm imports offset recent generator retirements, resulting in little change to the NPCC-New England ARM for this winter. New England continues to closely monitor regional energy adequacy, particularly during extended cold snaps where constrained natural gas pipelines contribute to rapid depletion of stored fuel supplies. ISO-NE's deterministic winter scenario analysis shows limited exposure to energy shortfalls this winter. In New England, winter energy concerns are highest in scenarios when stored fuels are rapidly depleted; during these periods, timely replenishment is critical to minimizing the potential for energy shortfalls.
   - **SERC-East**: The winter peak demand forecast has increased by 700 MW (1.6%) since last winter, while winter firm capacity has declined, resulting in lower reserves. SERC-East has changed from a summer-peaking area to potentially peaking during both summer and winter. This is due to the continued addition of solar photovoltaic (PV) generation that shaves off summer peak demand and a trend toward electrification of heating that drives up winter peak demand. All-hours probabilistic analysis from SERC found some load-loss hours (<0.1 hrs) and small amounts of expected unserved energy, with the highest risk occurring during above-normal peak demand and early morning hours when solar output is absent.
   - **SERC-Central:** Additional demand response and flat load growth since last winter is offsetting declining resource capacity (down 1,120 MW), resulting in little change to the ARM at 30.5%. There are adequate resources for normal winter peak demand; however, higher levels of demand that can occur during extreme cold temperatures can result in insufficient reserves that operators would need to manage with non-firm imports and potential energy emergencies.
   - **Texas RE-ERCOT:** Strong load growth from new data centers and other large industrial end users is driving higher winter electricity demand forecasts and contributing to continued risk of supply shortfalls. For the upcoming winter season, Texas RE-ERCOT is expected to continue facing reserve shortage risks during the peak load hour and high-

[1] See detailed reports on the January 2024 and January 2025 Arctic Storms, Winter Storm Elliott, and Winter Storm Uri.

net-load hours, particularly under extreme load conditions that accompany freezing temperatures. Elevated forced outage of thermal resources and reduced output from intermittent resources during these conditions exacerbates the risk of supply shortfalls. In winter, peak demands typically occur before sunrise and after sunset coinciding with the unavailability of solar generation making the system dependent on wind generation and dispatchable resources. Data centers are altering the daily load shape due to their round-the-clock operating pattern, lengthening peak demand periods. Additional battery storage and demand-response resources since last winter help mitigate shortfall risks. However, with the continued flattening of the load curve, maintaining sufficient battery state of charge will become increasingly challenging for extended periods of high loads, such as a severe multi-day storm like Winter Storm Uri.

- **WECC-Basin**: There is sufficient capacity in the area for expected peak conditions; however, Balancing Authorities (BA) are likely to require external assistance during extreme winter weather that causes thermal plant outages, adverse wind turbine conditions, and natural gas fuel supply issues for area internal resources. External assistance may not be available during region-wide extreme winter conditions. With an expected winter peak demand of 11.1 GW, under an extreme combination of generator derates and outages, the region could be short 1.6 GW before imports. Forecasted net internal demand has increased 1% since last year, with little change in winter capacity. Note that the WECC-Basin assessment area includes Utah, southern Idaho, and a portion of western Wyoming. In prior WRA reports, this part of the BPS was included as part of the WECC-NW assessment area. The *2025–2026 WRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.

- **WECC-NW**: Like WECC-Basin, there is sufficient capacity in the area for expected peak conditions; however, BAs are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year. Over 3 GW of new resources have been in development for the assessment area this year, primarily battery storage, solar PV, and wind resources. Delays that threaten timely completion of these resource additions will make the area more reliant on imports to meet peak demand.

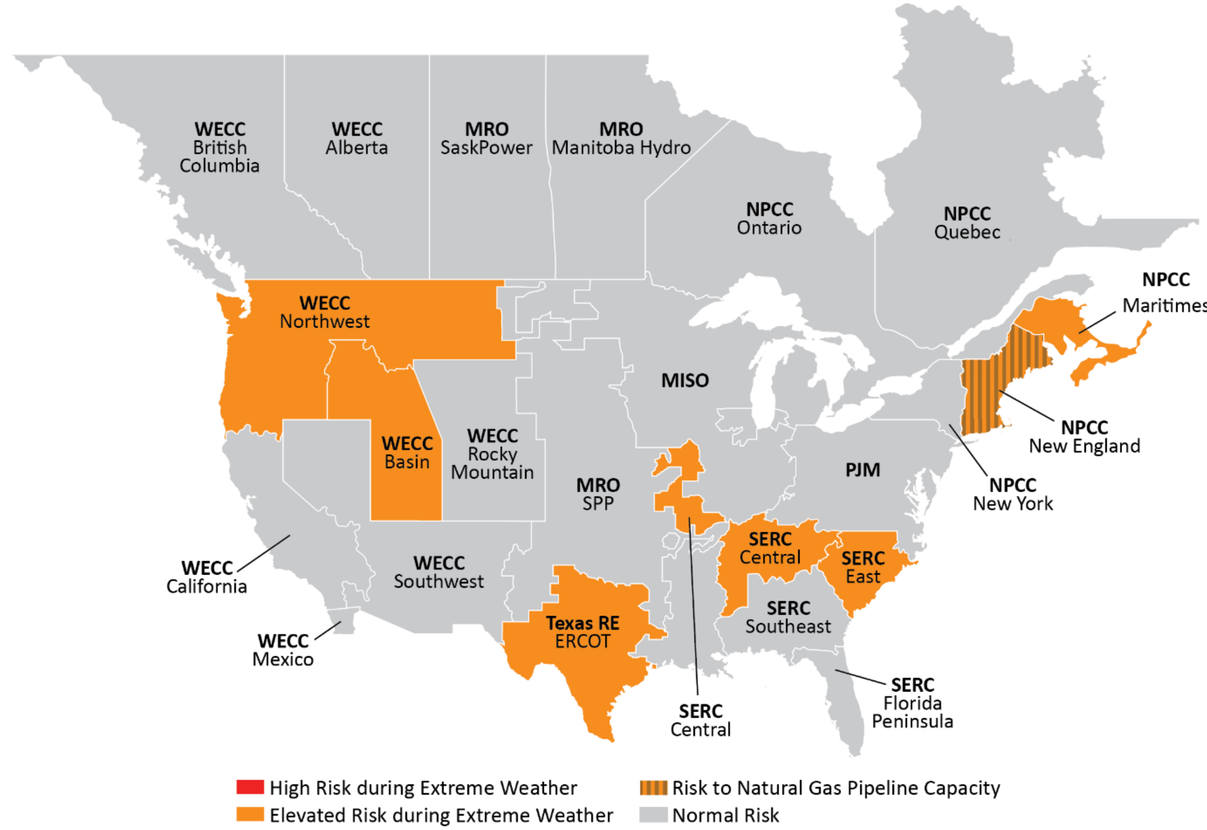


Figure 1: Winter Reliability Risk Area Summary

2. **The performance of natural gas production and supply infrastructure during peak winter conditions will again have a significant effect on BPS reliability.** Natural gas is an essential fuel for electricity generation in winter. Winter fuel supplies for thermal generators must be readily available during the periods of high electricity and natural gas demand that accompany extreme cold weather. Yet these periods are the most challenging for natural-gas-fired Generator Operators to obtain sufficient fuel and delivery. Natural gas production often falls off in extreme winter temperatures as supply infrastructure is affected by freezing issues, and Generator Operators that fail to secure firm fuel delivery are frequently unable to access fully subscribed pipelines. Evidence from the past two winters indicates notable improvement in the delivery of natural gas to BPS generators since winter storms Elliott and Uri with overall less natural gas production decline during cold weather and fewer natural gas infrastructure

force majeures.[2] Still, natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America, resulting in uneven application of protections and continued supply risks during extreme conditions. Furthermore, timing misalignments between the natural gas and electric markets continue to challenge generator fuel procurement in advance of severe winter conditions that occur over winter holiday weekends. As winter approaches, NERC encourages all entities across the gas-electric value chain—from production to the burner tip—to take all necessary preparations for extreme cold and keep natural gas flowing and the lights on.

3. **Cold weather Reliability Standards first introduced in 2023 have been improved prior to the upcoming winter and address recommendations from winter storms Elliott and Uri.** In September 2025, the Federal Energy Regulatory Commission (FERC) approved EOP-012-3 with an effective date of October 1, 2025, concluding the development of Reliability Standards for generator cold weather preparedness.[3] The EOP-012 Reliability Standard contains requirements for generator freeze protection measures, cold weather preparedness plans, and operator training. Among the improvements in the new version are enhanced and expanded requirements to ensure that Generator Owners (GO) are implementing corrective actions to address known issues affecting their ability to operate in cold weather in a timely manner. NERC collects data on the winterization of generating units, which, in conjunction with NERC's monitoring of BPS performance and analysis of cold weather events, helps determine the effectiveness of Reliability Standards. NERC submitted to FERC its first annual *Cold Weather Data and Analysis* informational filing in October 2025.[4] Based on the data reported this year, 96% of the total net winter capacity reported extreme cold weather temperatures (ECWT) at or below 32 degrees Fahrenheit, triggering winter preparedness measures under the Cold Weather Preparedness Standard, and 99% of total net winter capacity in the continental US reporting the ability to operate at the calculated ECWT. As the first such report, this *Cold Weather Data and Analysis* filing provides a benchmark for future analysis.

Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

- Reliability Coordinators (RC), BAs, and Transmission Operators (TOP) in the elevated risk areas identified in the key findings should review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially high generator outages and extreme demand levels. Operators should review NERC's Resources on Cold Weather Preparations.
- GOs should complete winter readiness plans and checklists prior to December, deploy weatherization packages well in advance of approaching winter storms, and frequently check and maintain cold weather mitigations while conditions persist.
- BAs should be cognizant of the potential for short-term load forecasts to underestimate load in extreme cold weather events and be prepared to take early action to implement protocols and procedures for managing potential reserve deficiencies. Proactive issuance of winter advisories and other steps directed at generator availability contributed to improved reliability during cold weather events of the past two winters.
- RCs and BAs should implement generator fuel surveys to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- Generator Owners/Operators of natural-gas-fired units should maintain awareness of potential extreme cold weather developing over holiday weekends and the implications for fuel planning and procurement that may result given the natural gas purchase close dates that precede long holiday weekends.
- State and provincial regulators can assist grid owners and operators in advance of and during extreme cold weather by maintaining awareness of BA, natural gas pipeline, and gas local distribution company (LDC) operational public announcements and notices, amplifying public appeals for electricity and natural gas conservation, and supporting requested environmental and transportation waivers.

[2] See *January 2025 Arctic Events | A System Performance Review*, April 2025
[3] See NERC's Statement on FERC September Open Meeting for summary and link to FERC's order.
[4] See 2025 Cold Weather Data Collection and Analysis Informational Filing

Risk Highlights

Escalating Winter Demand

Winter electricity demand is rising at the fastest rate in recent years, particularly in areas where data center development is occurring. After several years of low (~1%) growth, total internal demand for the BPS is forecast to increase by 20.2 GW (2.5%) over last winter's forecast. The changes in forecasted net internal demand for each assessment area are shown in **Figure 2** below.[5] Assessment areas develop these forecasts based on historical load and weather information as well as future projections. Most assessment areas are projecting an increase in peak demand. SaskPower, PJM, the U.S. Southeast, and parts of the U.S. West have the largest increase in peak demand forecasts.

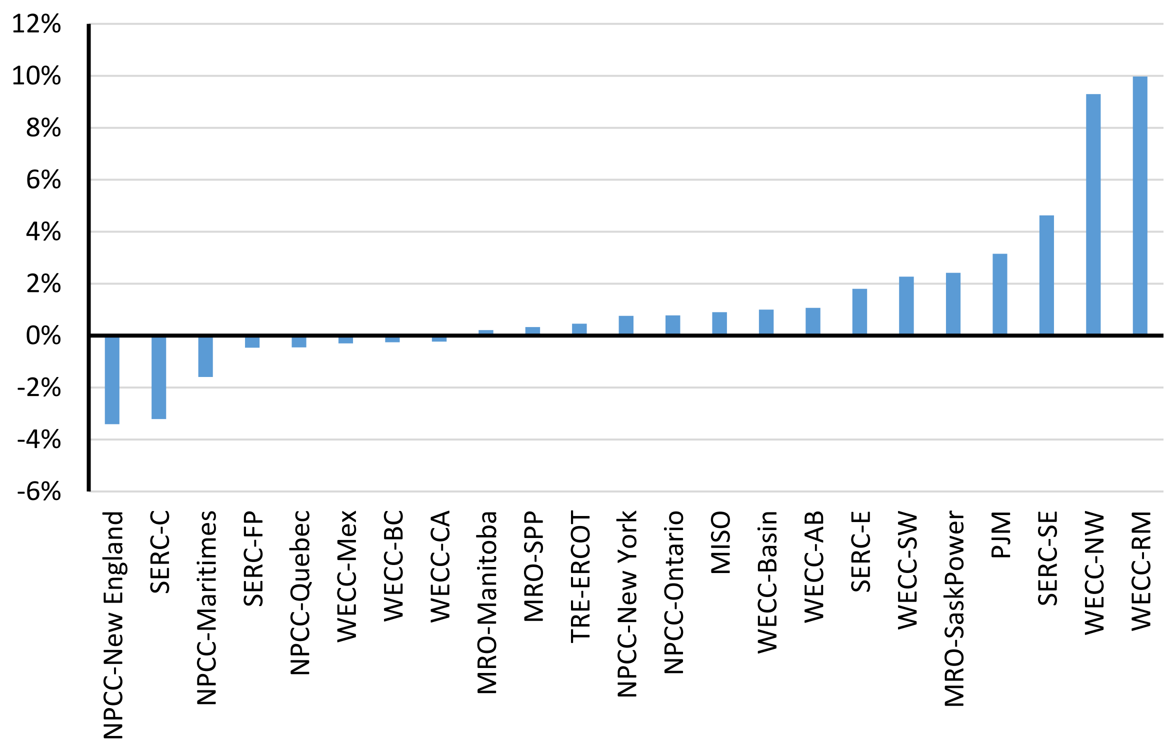


Figure 2: Change in Net Internal Demand—Winter 2025–2026 Forecast Compared to Winter 2024–2025 Forecast

[5] See **Data Concepts and Assumptions** section for demand definitions.

Resource Trends

BPS resources are growing, but at a slower rate than demand is rising. Battery and solar facilities were the leading resource types added to the BPS since last winter. Solar resources, however, often do not supply output during hours of peak winter demand. Growth in demand response is also contributing to BPS resources for the upcoming winter. **Table 1** shows the total change in BPS resources since last winter. For battery, solar, and wind resources, the table includes change in both nameplate (installed) capacity as well as the change in on-peak demand capacity, which is the capacity that resources are expected to provide in their area during the time of peak demand. For assessment-area specific information see **Variable Energy Resource Contributions** section.

Table 1: BPS Resource Change from Winter 2024–2025 to Winter 2025–2026

Resource	Net Change Nameplate Capacity (MW)	Net Change Peak Demand Capacity (MW)
Total Generator Capacity		1,335
Battery	19,659	11,121
Solar	11,097	1,176
Wind	-562	-14,238
Thermal and Hydro		3,276
Demand Response		8,112
Total Resources		9,447

Total BPS resources for serving winter peak demand, including generating capacity and demand response, have increased since last winter by 9,447 MW. Sizeable additions in battery resources and some new natural gas-fired generators contribute to the increase in resource capacity. However, the increase is offset by lower on-peak capacity values for wind resources, which are the result of revised valuations of wind resource capability at peak demand hours in some areas.[6] As a result, BPS generator capacity for winter peak demand makes up only a small portion of the total BPS increase. Generation accounts for 1,335 MW of the total 9,445 MW increase, while the larger share comes from demand response programs. Area specific information on demand response is provided in the **Demand and Resource Tables**.

The recent trend in resource additions is contributing to higher risk of electricity supply shortfalls in winter. BA operators are likely to face higher winter demand without a comparable increase in supply resources. Furthermore, the types of resources that are growing the most-- battery resources and

[6] Since last winter, ERCOT and MISO have implemented new methods for determining capacity contributions that result in lower wind and solar resources contributions at peak demand. See ERCOT's Resource Adequacy page and MISO's *Planning Year 2025-2026 Wind and Solar Capacity Credit Report*.

demand response—have unique characteristics that operators will need to account for and could limit the use of these resources in extreme winter conditions. Battery energy is reliable when it can be dispatched and has sufficient charge for the period it is needed, yet little time to recharge can be expected during extreme winter weather. System operators will need good visibility on battery state of charge and should anticipate that some extreme winter events will cause these resources to become depleted when needed. Demand response is limited by contract terms, which typically specify how often and for how long the resource may be used. Other resource types are also challenged in winter (see **Thermal Generator Fuel Adequacy and Security**). As BAs grapple with higher demand in most parts of the BPS, they will do so with resources that are becoming increasingly complex to dispatch especially in winter.

Thermal Generator Fuel Adequacy and Security

The performance of the thermal generator fleet remains critical to winter BPS operations. Winter fuel supplies for thermal generators must be readily available during periods of high demand and extreme cold weather. Generally, fuel adequacy for the thermal generating fleet is bolstered through strategic infrastructure investments and fuel stockpiling that increases the certainty of having fuel on hand that can be converted to electricity when needed. Because of this, winter performance of thermal generators is inextricably linked to extraction, processing, storage, and delivery infrastructure for a variety of fuels. Fuel supply risks have been noted in recent years' WRAs related to coal and natural gas availability and illustrate the interconnected nature of these critical energy infrastructure systems.

BPS stakeholders across North America note multiple fuel-related issues that are being monitored entering the winter season. For example, while coal represents a waning share of the overall resource mix, it continues to play an important role in meeting demand during extreme winter weather events, and oil inventories at dual-fuel gas-oil generators lessen risks related to natural gas deliverability in infrastructure-constrained regions, especially during the winter. Notably, it is infeasible or prohibitively costly to stockpile natural gas locally at power plants, and this exposes the BPS to the risk profile of the constituent systems that comprise the supply and delivery of this just-in-time fuel.

Natural Gas Generator Fuel Supplies

Natural gas generators remain a crucial part of on-peak resources meant to meet winter electricity demand across much of North America. While many Generator Owners and Operators secure backup fuel supplies at critical gas-fired generators, particularly in the northeastern United States and Florida, large contributions to the on-peak winter resource mix by single-fuel natural-gas-fired generators remain across North America (see **Figure 3**).

Natural gas generator performance can be threatened when natural gas supplies are insufficient or when natural gas infrastructure is unable to maintain the flow of fuel to critical generators. Grid operators continue to acknowledge and enhance their winter planning processes to firm up their fuel supplies and guard against natural gas disruptions, but winter storms Uri and Elliott demonstrated that combinations of natural gas flow restrictions and supply insufficiency can occur regardless of whether cold temperatures are common or uncommon in the region and can affect more than one BA area concurrently.

Many BPS areas that regularly experience cold weather events, like New England, have adopted mitigating technologies to lessen the impact of natural gas shortages through generator dual-fuel capability and stored backup fuel. In those areas, prolonged cold weather events present a risk of rapid depletion of stored backup fuel. Robust regional and distributed storage investments and winter planning for timely fuel replenishment are critical to minimizing potential energy shortfalls in the operational time frame in these areas.

Natural gas and electricity infrastructures have the added complexity of interdependence. Electricity is used to power some facilities, such as compressor stations and processing plants that make up natural gas infrastructure. These interdependencies mean that reliability events that originate on one system have the potential to affect the other and worsen the overall event magnitude or duration.

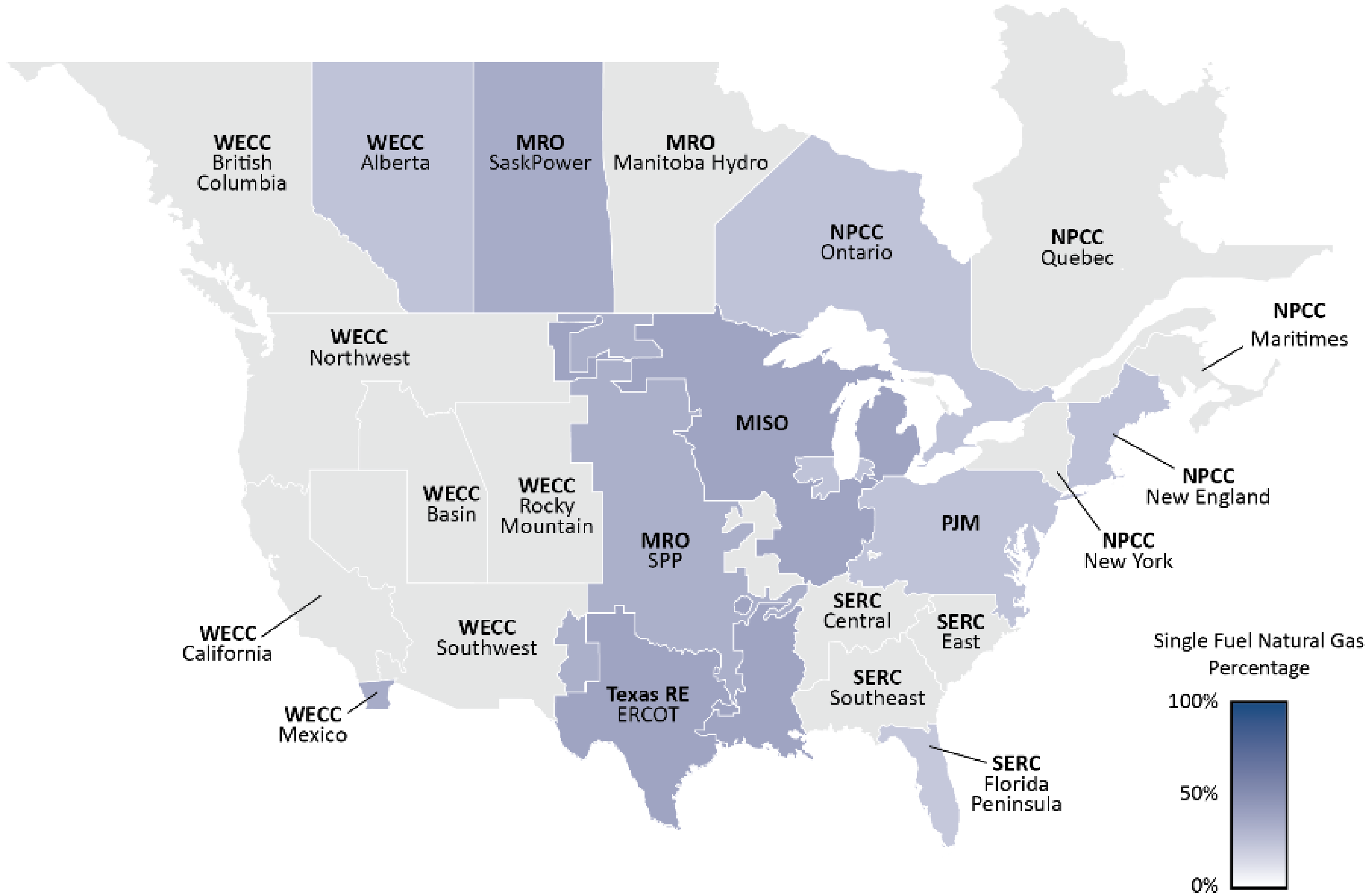
Natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America. Texas is an exception, where the Railroad Commission of Texas adopted rules to require critical natural gas facilities to implement weather-related emergency preparation measures.[7] Lack of consistent standards for natural gas infrastructure protections will result in uneven application of freeze protections and continued supply risks during extreme conditions in many areas.

These considerations have driven higher levels of coordination to ensure sustained reliable operation of the natural gas and electricity systems. While a FERC and ERO staff review of system performance during the January 2025 arctic events[8] details improvements in electric and natural gas coordination since winter storms Uri and Elliott, the review also identifies continuing gaps between the electricity and natural gas industries that remain entering the 2025–2026 Winter season. These include natural gas scheduling challenges during winter holiday weekends, market time frame and process incompatibility, and electric power entities' lack of visibility into operational impact data from natural gas producers and suppliers.

[7] See Railroad Commission of Texas weatherization rule.

[8] FERC, NERC Issue Report on System Performance During the January 2025 Arctic Weather | Federal Energy Regulatory Commission

The U.S. Energy Information Administration (EIA)[9] anticipates a slightly milder winter than last year across much of the United States, especially in the Northeast, leading to a projection that households will consume approximately 2% less natural gas than last winter. Working natural gas storage inventories are about 5% above the previous five-year average in the United States heading into the winter season. The EIA attributes this relative surplus in part to robust production this summer and lower-than-expected natural gas consumption by power generators.



Note: Areas with less than 20% natural gas are shown in light gray.

Single-Fuel Natural-Gas-Fired Generation

	Winter Capacity (GW)	Contribution to Total Winter Resource Mix
MISO	63.9	38%
TRE-ERCOT	53.0	38%
WECC-MX	2.2	34%
MRO-SaskPower	2.5	34%
SPP	33.4	32%
NPCC-New England	12.1	24%
PJM	60.9	23%
WECC-AB	13.9	23%
NPCC-Ontario	8.0	23%
SERC-FP	45.6	21%
WECC-CA	35.9	18%
WECC-SW	21.5	17%
WECC-Basin	4.9	16%
WECC-RM	6.2	14%
SERC-C	17.0	13%
SERC-SE	21.5	13%
WECC-NW	8.7	12%
SERC-E	11.3	9%
NPCC-New York	5.0	8%
NPCC-Maritimes	0.5	7%
MRO-Manitoba	0.3	4%
WECC-BC	0.1	1%
NPCC-Quebec	0.0	0%

Figure 3: Single-Fuel Natural-Gas-Fired Generation Capacity Contribution to the 2025–2026 Winter Generation Mix

[9] See the U.S. Energy Information Administration's [Winter Fuels Outlook 2025–26]

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in Table 2.

Table 2: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels (RML); or • Probabilistic indices exceed benchmarks, e.g., loss of load hours (LOLH) of 2.4 hours over the season; or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season); or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions);[2] or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins (ARM), which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins with typical forced outage levels and for the most extreme seasonal risk scenarios are provided in Table 3.

Table 3: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Reserve Margin with Typical Outages	Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	49.5%	22.3%	3.7%
MRO-Manitoba	13.7%	11.4%	6.1%
MRO-SaskPower	35.1%	29.0%	16.1%
MRO-SPP	56.5%	29.4%	16.9%
NPCC-Maritimes	16.9%	12.5%	-4.7%
NPCC-New England	58.9%	45.4%	8.7%
NPCC-New York	78.2%	52.4%	16.2%
NPCC-Ontario	28.6%	21.8%	13.2%
NPCC-Québec	15.2%	15.1%	5.0%
PJM	35.6%	24.8%	15.6%
SERC-C	30.5%	22.4%	-0.9%
SERC-E	21.9%	17.5%	3.0%
SERC-FP	41.7%	28.3%	25.6%
SERC-SE	39.7%	24.7%	17.7%
TRE-ERCOT	36.0%	25.2%	-20.0%
WECC-AB	35.2%	32.4%	10.0%
WECC-Basin	29.6%	19.7%	-21.1%
WECC-BC	25.9%	25.8%	15.4%
WECC-CA	82.3%	73.7%	57.9%
WECC-Mex	83.1%	79.4%	52.9%
WECC-NW	30.9%	29.5%	-8.5%
WECC-RM	61.7%	53.2%	10.0%
WECC-SW	104.4%	90.1%	50.1%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential winter peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 3**, each assessment area's ARMs are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Areas highlighted in orange in **Figure 1** above have been identified as having resource adequacy or energy risks for the winter and are included in the **Key Findings** section's discussion that follows. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced-outage margin is the same as the ARM, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the winter season. Results are summarized in **Table 5**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include loss of load expectation (LOLE), loss of load hours (LOLH), expected unserved energy (EUE), and the probabilities of energy emergency alert (EEA) declarations (see **Table 4** for a description of EEA levels).

Table 4: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required operating reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum operating reserve requirements.
EEA 3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum operating reserve requirements.

Energy Emergency Alerts

The combination of above-normal generation outages, low resource output, and peak loads as occurred during the extreme cold weather events of Winter Storm Uri in 2021 and Winter Storm Elliott in 2022 are ongoing winter reliability risks. When supply resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ EEAs to maintain balance between available capacity and energy and real-time demand. A description of each EEA level is provided above.

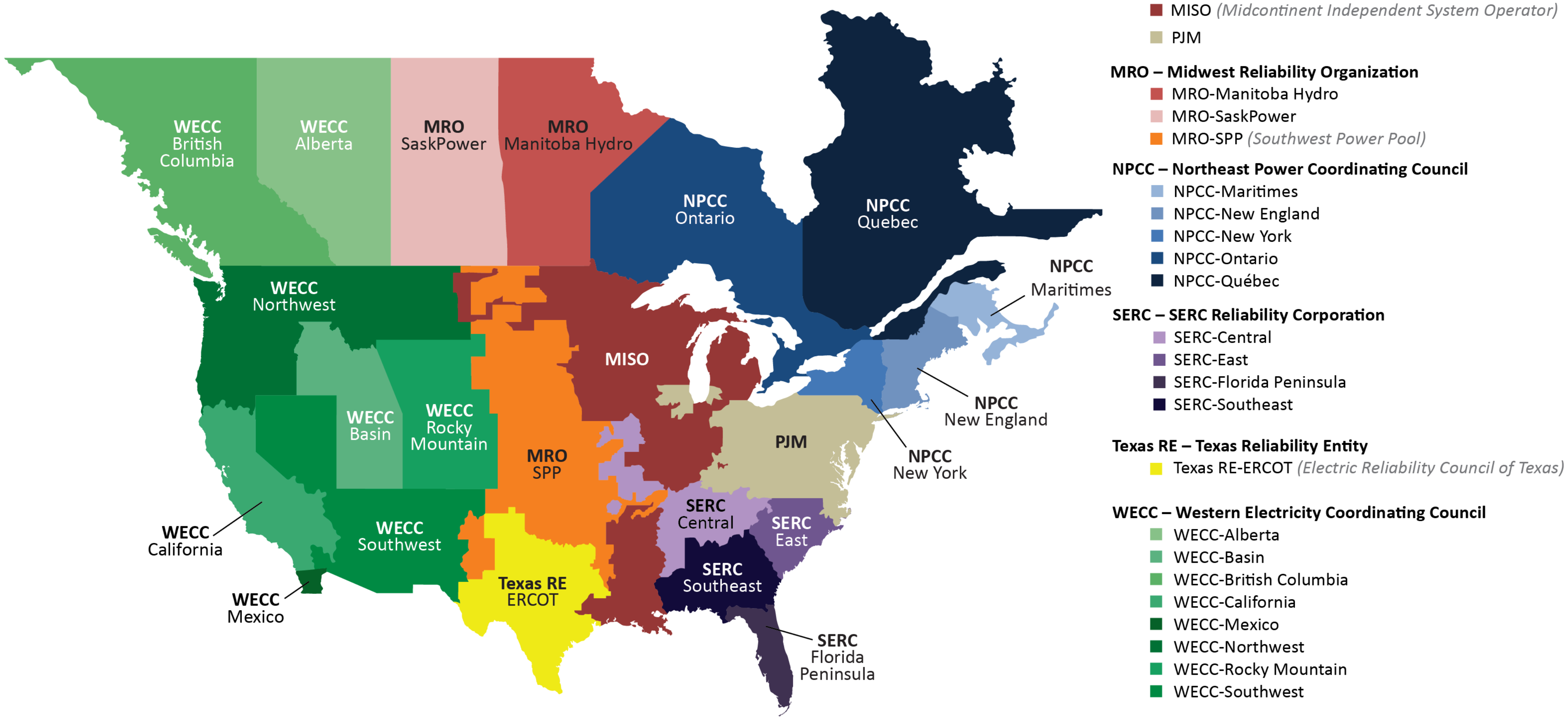
Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	Deterministic	MISO does not provide a probabilistic assessment for the WRA. MISO applies a deterministic look at expected system conditions, looking at generation availability under typical and extreme outages and looking at a typical 50/50 load forecast and an extreme 90/10 load forecast. For the upcoming winter season, under an extreme outage and extreme 90/10 load forecast, this is the riskiest scenario for the MISO footprint. This scenario produces the shortest actual reserve margin for January.
MRO-Manitoba	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 *Long-Term Reliability Assessment* (LTRA) found no load-loss or unserved energy hours for 2026.
MRO-SaskPower	Probability-based capacity adequacy assessment	SaskPower's probabilistic assessment for the 2025–2026 Winter indicates that risk of shortfalls is lower than the previous winter. LOLH for an elevated risk scenario for the 2025–2026 Winter season is 0.08 hours. The month with the highest LOLH is December (0.05 hours).
MRO-SPP	NERC 2024 ProbA	Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
NPCC	NPCC conducted an all-hour probabilistic reliability assessment that included detailed neighbor modeling and consisted of a base case and severe case examining low resources, reduced imports, and higher loads. The assessment evaluates the probabilistic indices of LOLE, LOLH, and EUE. The highest peak load scenario has an approximately 7% probability of occurring.	
NPCC-Maritimes	The Maritimes Area low-likelihood resource case assumed: wind derated by 50% for every hour in December through February and a 50% natural gas capacity curtailment for December through February (dual-fuel units assumed reverting to oil) and reduced transfer capabilities.	The preliminary assessment indicates that established operating procedures are not sufficient to maintain a balance between electricity supply and demand. Under highest peak load levels, the Maritimes Area shows a notable likelihood of utilizing its operating procedures such as reducing 30-minute reserves, initiating interruptible loads, and reducing 10-minute reserves to maintain system reliability during the upcoming winter period.
NPCC-New England	The New England Area low-likelihood resource case assumed: 500 MW of additional maintenance outages, ~4,513 MW of gas-fired generation unavailable due to fuel supply constraints, and 50% reduced import capabilities of external ties.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand
NPCC-New York	The New York Area low-likelihood resource case assumed: ~500 MW of extended maintenance in southeastern New York, 600 MW of cable transmission reduction across HVdc facilities, and ~5,000 MW of generation unavailable due to fuel delivery issues.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period, for all the scenarios modeled.
NPCC-Ontario	An energy assessment for the Ontario Assessment Area was conducted for two scenarios: firm resources and firm demand with expected weather, and planned resources with planned demand with expected weather.	No cumulative LOLH or EUE risks were identified over the entire November-to-April winter season for both scenarios modeled.

Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Québec	The Québec Area low-likelihood resource case assumed 1,000 MW of generation reductions.	The preliminary results of this assessment indicate that established operating procedures are sufficient to maintain a balance between electricity supply and demand if needed. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period for all the scenarios modeled
PJM	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic study for 2025–2026 Winter is not provided for the WRA. PJM performed probabilistic analysis for 2026-2027 winter as part of the 2024 ProbA summarized in NERC's 2024 LTRA. The results of this study indicate risk of load loss (<0.1 hours) and unserved energy during winter months. For the upcoming winter, load-loss hours are expected to be less than this value because forecasted load is lower and anticipated resource capacity is higher than the case studied for the 2024 ProbA.
SERC	Based on the 2024 NERC Probabilistic Assessment (ProbA) base-case result. SERC's assessment used 38 years of historical load shapes to assess the resource adequacy of years 2026 and 2028, primarily based on data from the 2024 Long Term Reliability Assessment (LTRA).	
SERC-Central		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
SERC-East		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found a small number of load-loss hours (<0.1) and EUE (61 MWh / 1 ppm) for 2026.
SERC-Florida Peninsula		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found negligible load-loss hours and EUE.
SERC-Southeast		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
Texas RE-ERCOT	ERCOT Probabilistic Reserve Risk Model	ERCOT's probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
WECC	The resource adequacy work performed at WECC used the Multi-Area Variable Resource Integration Convolution (MAVRIC) model for the 2025 LTRA. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and ProbA.	
WECC-AB		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Basin		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-BC		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-CA		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Mexico		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Rocky Mountain		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-NW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026. Results for a case where new resource additions are not completed for the upcoming winter found some EUE and LOLH.
WECC-SW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

Regional Assessments Dashboards

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

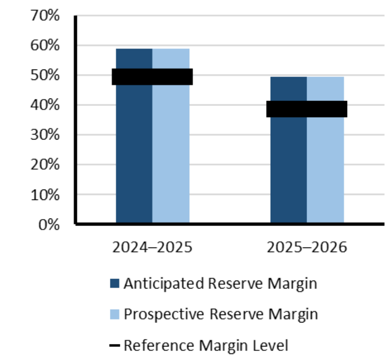


MISO

The Midcontinent Independent System Operator, Inc. (MISO) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery of electricity to approximately 45 million people by managing regional transmission operations as well as energy and ancillary services markets and advising on long-term resource planning. The MISO footprint includes 39 Local BAs and more than 550 market participants. MISO operates one of the world's largest organized electricity markets, with its members operating a system that consists of over 77,000 miles of transmission lines and approximately 1,888 generating units. The peak electricity demand on the MISO system currently occurs during the summer season. MISO's footprint lies across three regional entities (MRO, RF, and SERC), but MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

- MISO expects limited risk in the 2025–26 Winter season as MISO was able to procure 6.1% more resources through the annual planning reserve auction than required by its minimum resource adequacy target. A further 3.3 GW of resources were available but not chosen to be committed for the winter season.
- Some risk has been identified for this upcoming winter season. In a high generation outage and high winter load scenario reliability is expected to be maintained by reliance upon operational mitigations that include non-firm energy transfers into the system, energy-only resources not subject to a must-offer requirement that may still offer into the energy markets, load-modifying resources, and internal transfers that exceed the Sub-Regional Import/Export Constraint (SRIC/SREC) between the MISO North/Central and South areas.
- MISO continues to coordinate with neighboring RCs and BAs to improve situational awareness and vet any needs for energy transfers to address extreme system conditions.
- MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency.
- MISO has implemented a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons.

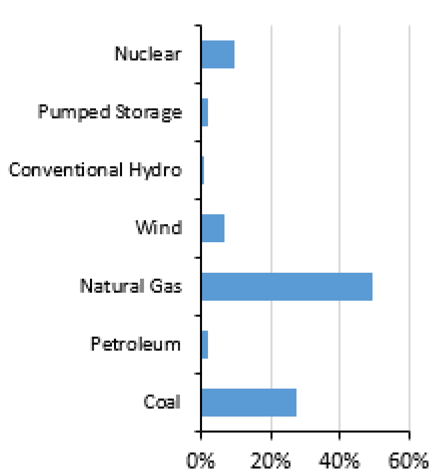
On-Peak Reserve Margin[10]



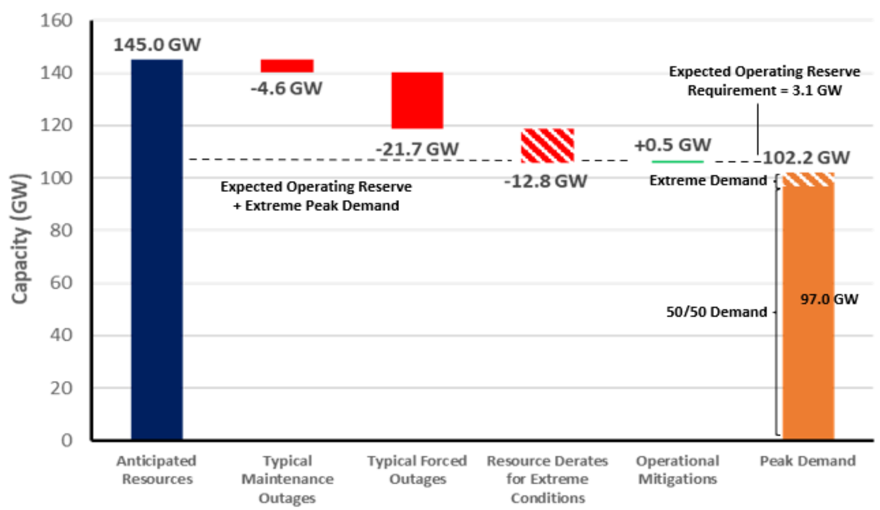
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with generator outages from freezing or fuel supply issues and low wind output result in the need to employ operating mitigations (i.e., demand response and transfers).

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: 50/50 net internal demand and additional demand during extreme weather conditions (e.g., Winter Storm Enzo) using member submitted data and historical load data

Typical Maintenance Outages: Rolling three-year winter average of peak-day maintenance and planned outages

Typical Forced Outages: Three-year average of all peak-day outages that were not planned

Resource Derates for Extreme Conditions: Represents derates aligning with the most extreme hour of each of the past 3 years,

Operational Mitigations: Non-firm energy transfers into the system, energy-only resources that do not have a must-offer requirement, or internal transfers that exceed the SRIC/SREC between the MISO North/Central and South regions

[10] The MISO Risk Scenario Assessment for the 2025-26 Winter Season is not directly comparable to that for the 2024-25 Winter Season as methodology improvements have been implemented.

MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter-peaking. Manitoba Hydro is its own Planning Coordinator (PC) and Balancing Authority (BA). Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

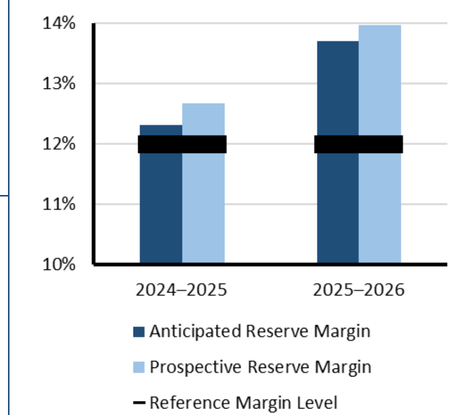
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Winter 2025–2026.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even under continued drought conditions.
- Manitoba Hydro is experiencing well below-average water supply conditions; however, the Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought.
- The ARM for Winter 2025–26 exceeds the 12% RML.

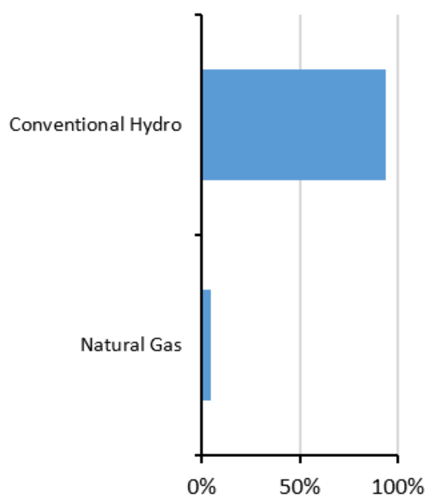
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

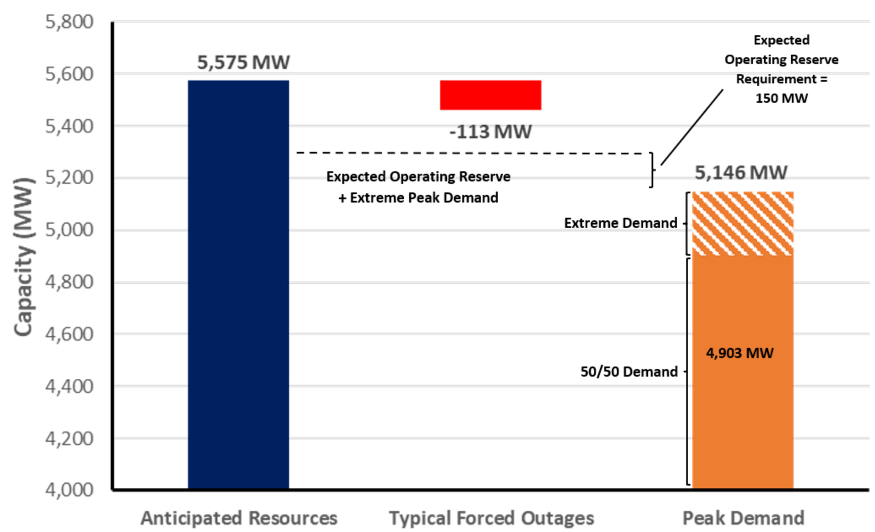
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of weather data

Typical Forced Outages: Accounts for average forced outages

MRO-SaskPower

MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections. Overall, SaskPower operates nearly 14,816 circuit-km of transmission lines, 65 high-voltage switching stations, and 191 distribution substations. Peak electricity demand on the SaskPower system currently occurs during the winter season.

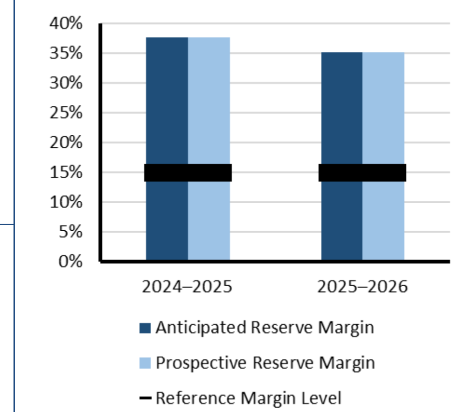
Highlights

- Saskatchewan experiences its peak load during the winter months due to extreme cold weather.
- Based on the planned maintenance, typical forced outages from historical data, and expected renewable generation under the normal and extreme demand conditions, SaskPower does not anticipate any reliability issues during the 2025–2026 Winter.
- During extreme winter conditions, SaskPower would utilize available demand-response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions to manage the situation.

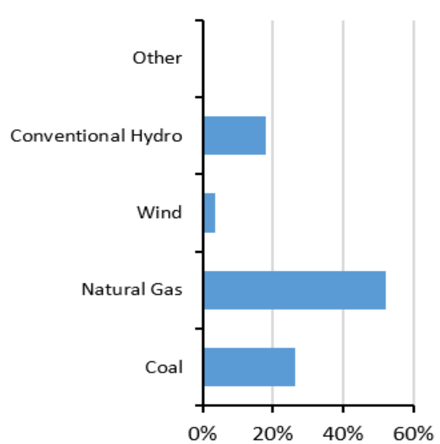
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

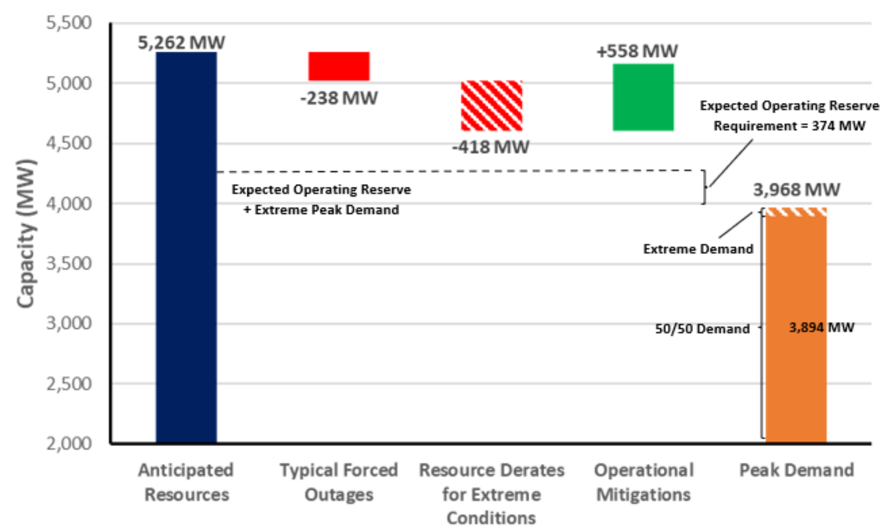
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Based on the historical load variability, SaskPower calculates a probability density function for load to simulate various scenarios that include extreme conditions.

Typical Forced Outages: Estimated using SaskPower forced outage model

Resource Derates for Extreme Conditions: Wind capacity is derated by 96% due to the cut-out of most wind farms below -30°C. Solar generation is expected to be fully unavailable under extreme conditions.

Operational Mitigations: Includes the non-firm import capability (360 MW) and generators in layup status (167 MW) that can be brought online with one to five days' notice; additional demand-side resources are estimated based on other demand response programs and non-firm loads that require 15 minutes to 2 hours of notification

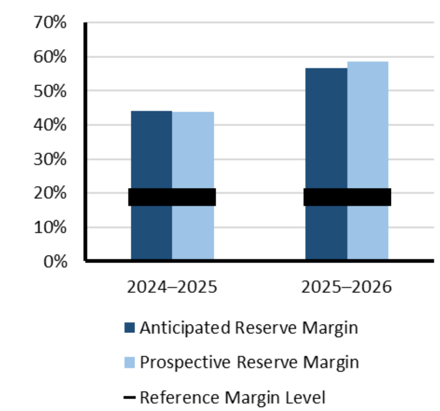
MRO-SPP

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

Highlights

- SPP anticipates that planning reserves are adequate for the upcoming winter season even as SPP continues to set new winter season load records.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2025–2026 Winter season but realizes that interruptions to fuel supply combined with higher penetration of variable energy resources could create unique operation challenges.
- SPP continues to work at enhancing communications and operator preparedness with neighboring regions to address potential electric deliverability issues associated with extreme weather events.
- To minimize conservative operations, EEAs, and mid-range forecast error uncertainty response in wind forecasts, SPP implemented several new operational mitigation processes and procedures to deal with high-impact real-time areas of reliability concern.
- SPP has proposed numerous resource adequacy initiatives, including addressing EUE standards, fuel assurance, winter planning reserve margins, outage policies, demand response, and accreditation; all were recently approved by FERC.

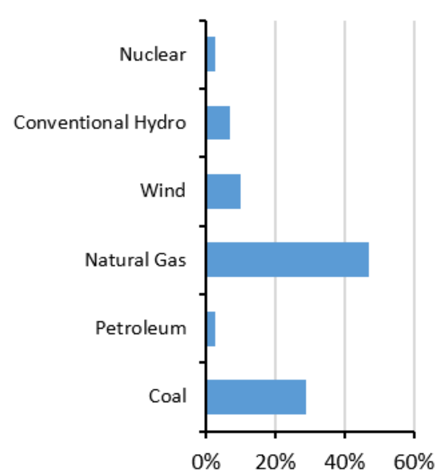
On-Peak Reserve Margin



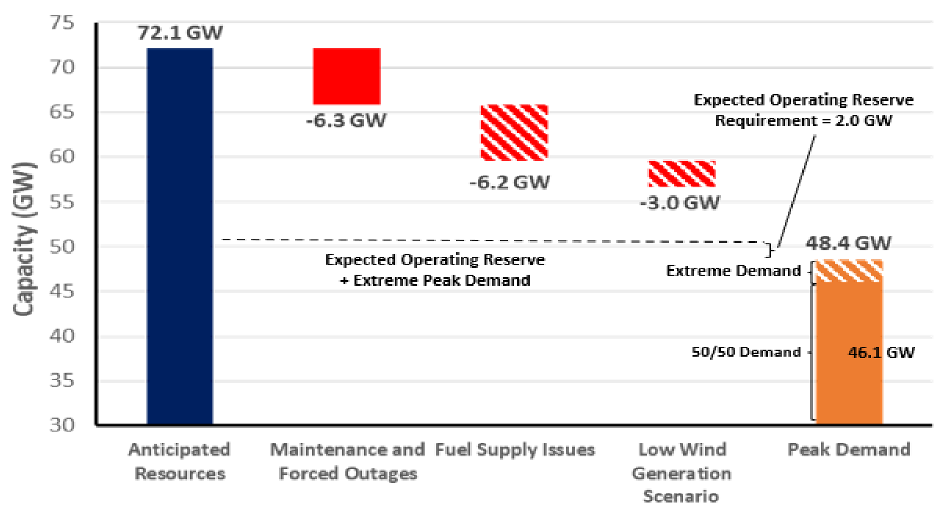
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast using historical data

Maintenance and Forced Outages: A capacity derate of 6.3 GW for maintenance outages, forced outages, and performance in extreme weather based on historical data

Fuel Supply Issues: BA derate of 6.2 GW based on MW capacity of gas-fired generators experiencing fuel supply issues in winter storm Elliott.

Low Wind Generation Scenario: 3 GW of wind potentially off-line when temperatures fall below their cold weather performance packages

NPCC-Maritimes

NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. state of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 1.9 million people. The New Brunswick Power Corporation (NB Power) is the balancing authority for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the balancing authority for Nova Scotia. NB Power's system is electrically interconnected with NPCC-Québec and NPCC-New England, and the electric systems in the provinces of Nova Scotia and Prince Edward Island have ties with New Brunswick but no direct ties with other assessment areas. Peak electricity demand in NPCC-Maritimes occurs during the winter season.

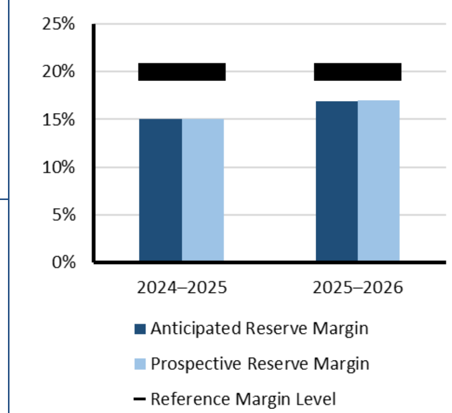
Highlights

- The Maritimes has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind, dual-fuel oil/gas, tie benefits, and biomass with no one type making up more than about 27% of the total capacity in the area.
- The Maritimes has long-term energy contracts in place for its winter supply and can purchase additional energy in the day-ahead and in real time as required.
- As part of the winter planning and preparation process, dual-fueled units will have sufficient supplies of heavy fuel oil stored on site to enable sustained operation in the event of natural gas supply interruptions.

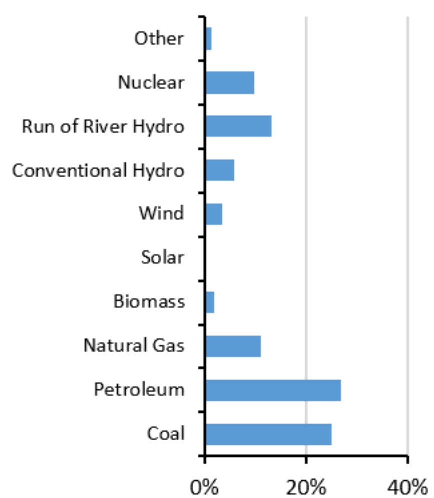
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates some risk of unserved energy and LOLH under high demand or low resource scenarios.

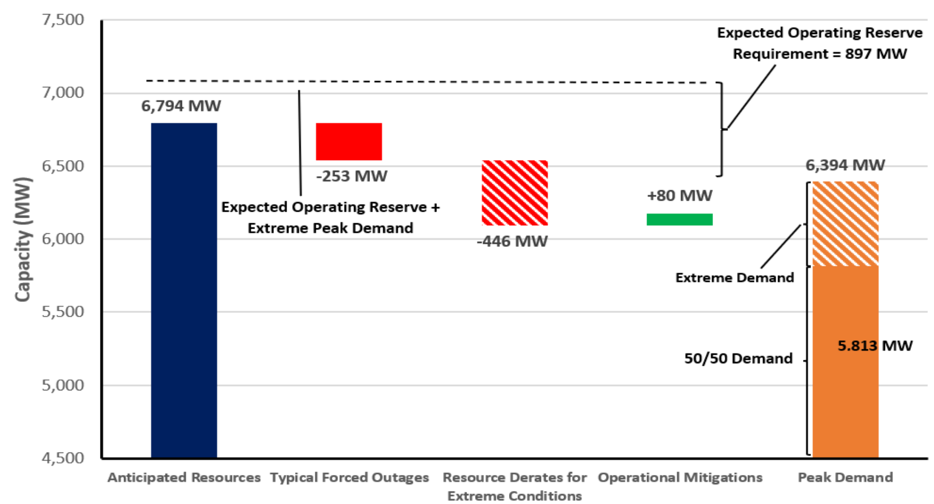
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Scenario peak load with adjustment calculated by adding a 10% margin of error to the peak internal demand forecast taken from the *Long-Term Reliability Assessment* (LTRA) for the 2025–2026 Winter period (aligns with the all-time winter peak, which occurred on February 4, 2024)

Typical Forced Outages: Based on historical operating experience

Resource Derates for Extreme Conditions: Based on ambient temperature thermal derates, wind derated to zero, as well as natural gas capacity derated by 50% due to supply issues

Operational Mitigations: Based on emergency operations and planning procedures in place including fuel switching

NPCC-New England

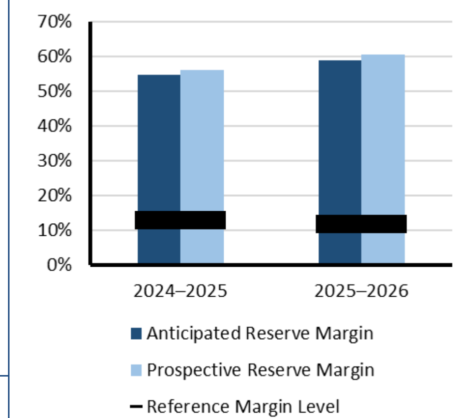
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- ISO-NE expects to meet its regional resource adequacy requirements this 2025–2026 Winter operating period without calling upon operating procedures to maintain a balance between electricity supply and demand.
- A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold spell given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and liquefied natural gas (LNG)).
- ISO-NE expects to have sufficient capacity resources to meet the 2025–2026 50/50 and 90/10 winter peak demand forecast of 19,616 MW and 21,125 MW, respectively, for the weeks beginning January 10, January 17, and January 24.
- ISO-NE has recently developed the Regional Energy Shortfall Threshold (REST) as an effort to quantify the tolerable risk of energy shortfall during extreme events. Within the 0.25% highest-risk scenarios, the REST thresholds are 3.0% normalized EUE over 72-hour periods and 18.0 hours over 21-day periods.
    - ISO-NE does not anticipate exceeding the REST criteria for Winter 2025–2026.

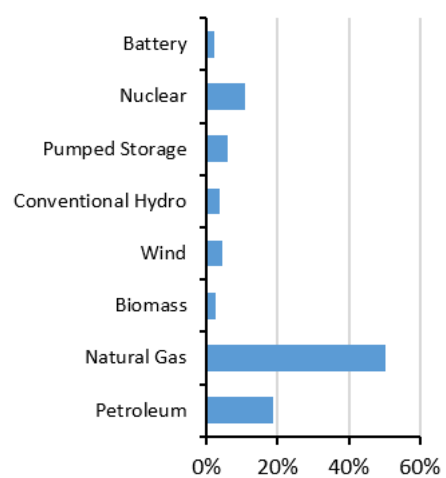
On-Peak Reserve Margin



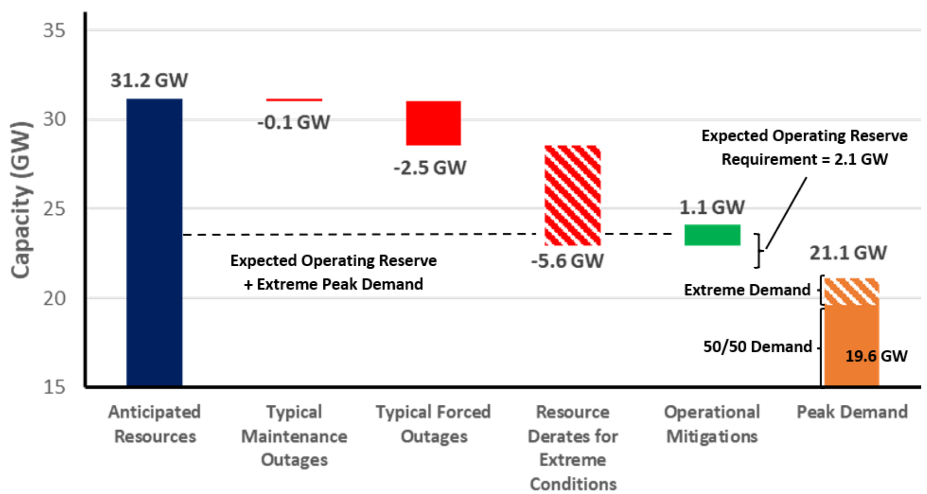
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with high generator outages could result in the need for operating mitigations (i.e., demand response and transfers). Prolonged extreme cold weather events that result in depletion of stored fuels can lead to resource shortfalls.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast capturing the region's coldest day in the last 30 years using current and future load models

Typical Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Resource Derates for Extreme Conditions: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply and cold weather-related outages

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures

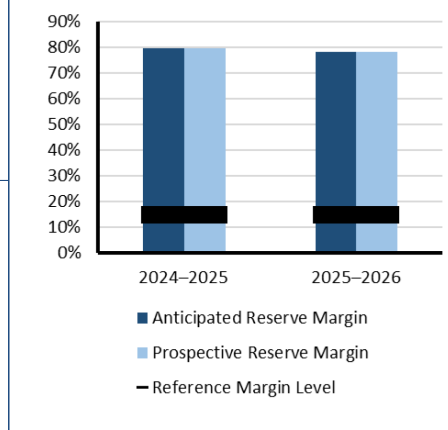
NPCC-New York

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

Highlights

- New York is presently a summer-peaking area, and no emerging reliability issues are anticipated during the 2025–26 Winter assessment period.
- Expected resources meet operating reserve requirements under the assessed demand and resource scenarios. A scenario involving an extended cold snap that causes above-normal demand and diminished natural gas supplies would result in low but sufficient reserves.
- The preliminary results of the NPPCC winter probabilistic assessment indicate that operating procedures are not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOL,H or EUE risks were indicated over the December–February winter period for all the scenarios modeled.

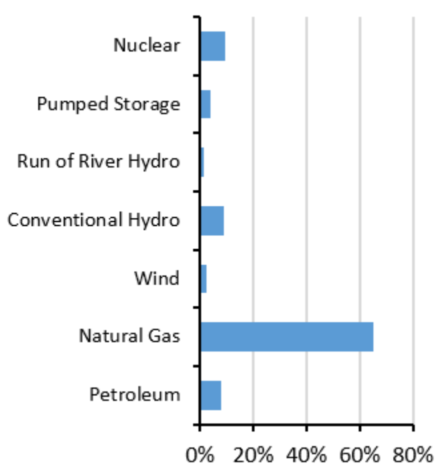
On-Peak Reserve Margin



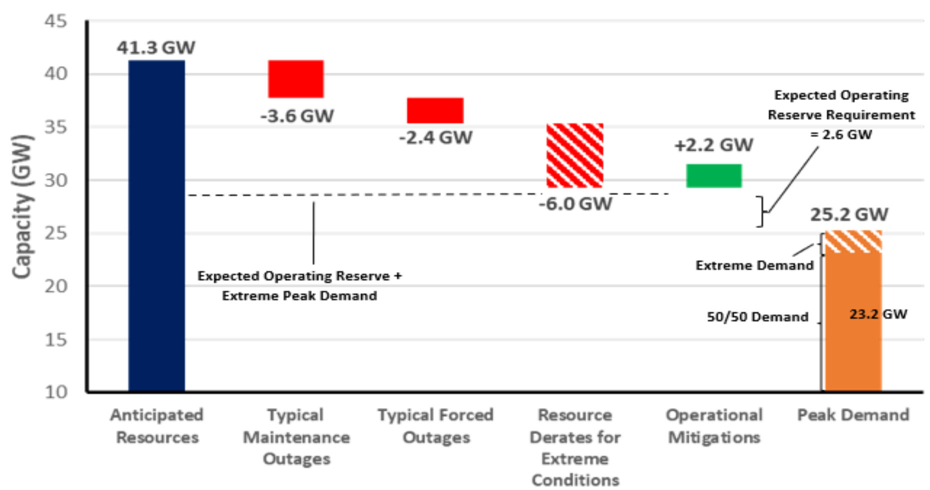
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed demand and resource scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Maintenance Outages: Based on planned scheduled maintenance

Typical Forced Outages: Based on 5–year averages from GADS data.

Resource Derates for Extreme Conditions: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather. Based on a 2025 analysis, approximately 6,307 MW of gas generation with non-firm fuel supplies could be unavailable.

Operational Mitigations: Based on NYISO operating procedures

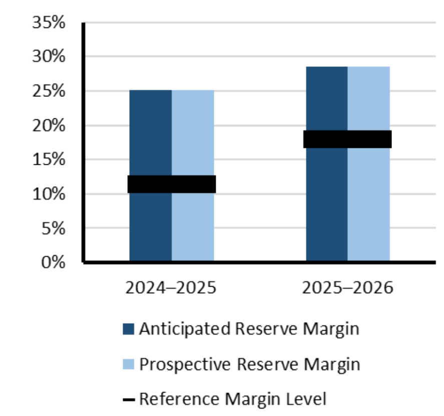
NPCC-Ontario

NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of almost 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority for the province of Ontario. NPCC-Ontario is electrically interconnected with NPCC-Québec, MRO-Manitoba, MISO, and NPCC-New York. Peak electricity demand in NPCC-Ontario occurs during the summer season.

Highlights

- As Ontario is a summer-peaking province, there is typically a lower risk of reliability issues during the winter than the summer. However, Ontario regularly experiences extreme cold weather in the winter.
- NPCC-Ontario is well prepared for Winter 2025–2026, and IESO expects that the electric system will remain reliable with reserve margins well above required levels.
- Operators and forecasters in Ontario work closely with neighboring jurisdictions to manage extreme weather events.
- Natural-gas-fired generators in Ontario are supplied by pipelines with access to the Enbridge Gas Dawn Hub and its associated storage facilities, which significantly reduces natural gas deliverability and reliability concerns by connecting those systems to several major gas transportation corridors, enabling access to multiple supply basins.

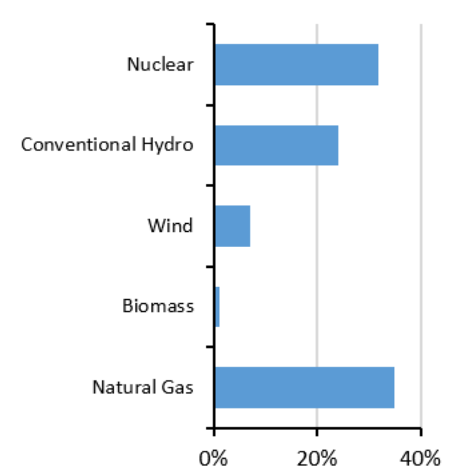
On-Peak Reserve Margin



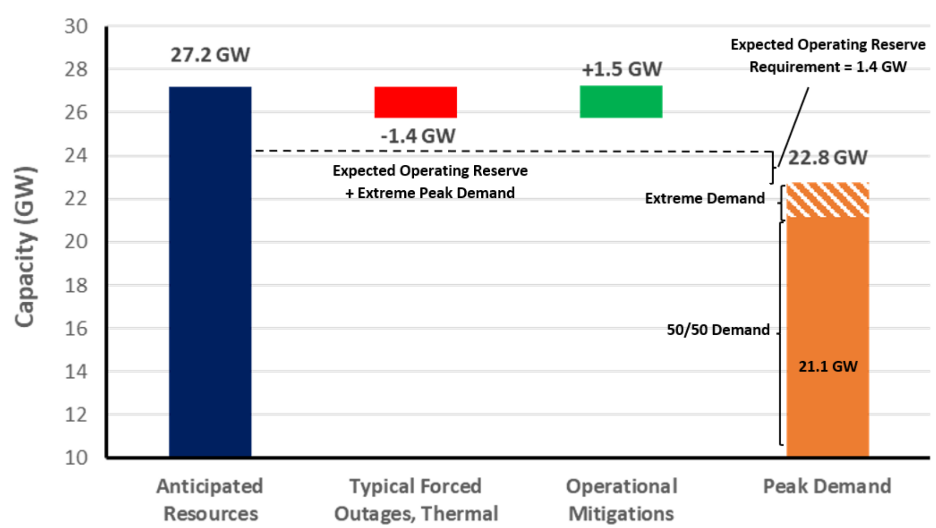
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand from 31 years of winter demand history

Typical Forced Outages, Thermal: Based on analysis of a rolling five-year history of actual forced outage data.

Operational Mitigations: Imports anticipated from **neighbors** during emergencies

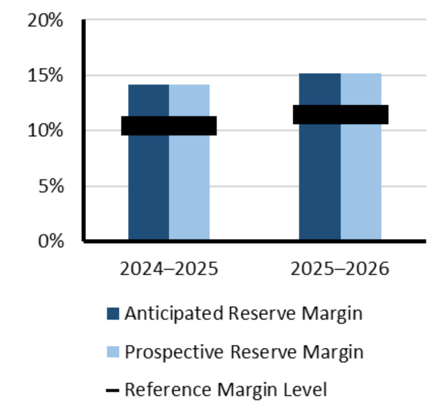
NPCC-Québec

NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the four electric Interconnections in North America. It is a predominately hydroelectric-generation-based system that is electrically interconnected with NPCC-Ontario, NPCC-New York, NPCC-New England, and NPCC-Maritimes. Peak electricity demand in NPCC-Québec occurs during the winter season.

Highlights

- NPCC-Québec projects adequate capacity margins above its reference reserve requirements and that system resource adequacy will be maintained for the province for the 2025–26 Winter assessment period.
- No hydropower performance issues are expected during extreme cold because of design criteria for cold weather.
- No fuel supply or transportation issues are anticipated for the upcoming winter season.
- While a slight decrease in net firm transfers has occurred since last winter (-89 MW), significant increases in demand-side management programs (+450 MW year-over-year) have been realized over the same period and are expected to compensate for this winter's modest expected load growth.

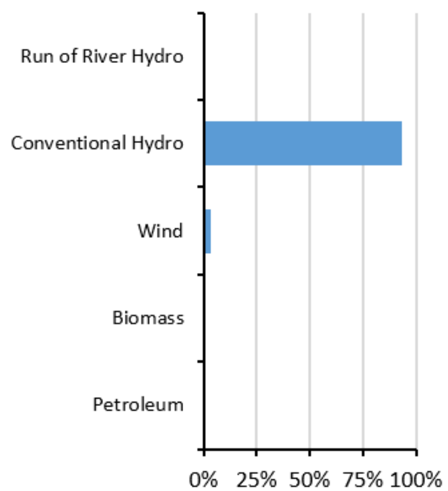
On-Peak Reserve Margin



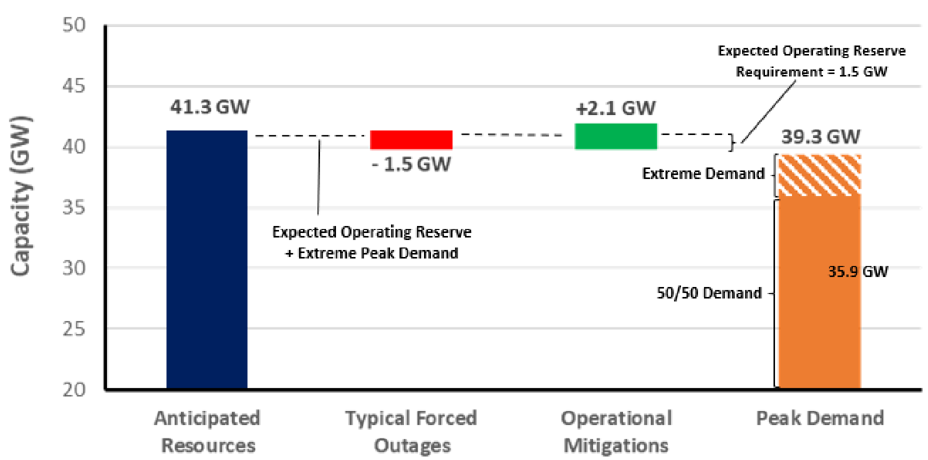
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 8:00 a.m.

Demand Scenarios: Demand forecasts include demand-side resources. The demand side resources are the same for the 50/50 and extreme demand scenarios. The extreme load forecast is determined at two standard deviations higher than the mean, which has a 6.06% probability of occurrence.

Extreme Derates: Maintenance outages and other deratings are already included in existing-certain capacity calculation. Wind capacity is 64% derated

Typical Forced Outages: Unplanned outages are 1,500 MW.

Operational Mitigations: Operational mitigations include imports from neighboring areas and reduction of reserves

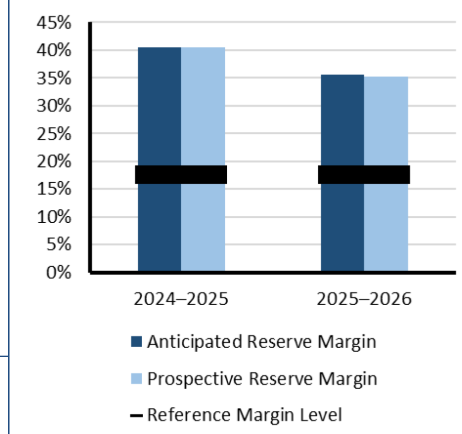
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM's footprint covers approximately 369,054 square miles and with an approximate population of 67 million people. PJM is the area's BA, Transmission and Resource Planner, interchange authority, TOP, transmission service provider, and RC. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

Highlights

- Due to the low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with highest loss-of-load risk remains the hour with highest forecasted demand.
- PJM is expecting little capacity adequacy risk during Winter 2025–2026 and expects around 35% installed reserves, which is above the target IRM of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- Last winter, PJM hit a new all-time winter peak, but generator preparations anticipating congestion and tight capacity projections led to sufficient reserves throughout the demand event and PJM's transmission system performed well.
- The decrease in reserves from Winter 2024–2025 is due to load increases and retirement of generation without like (non-solar dispatchable) replacement generation.

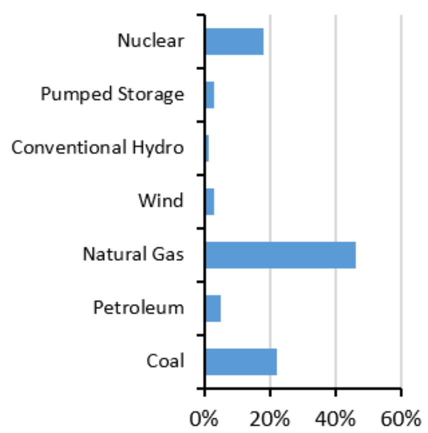
On-Peak Reserve Margin



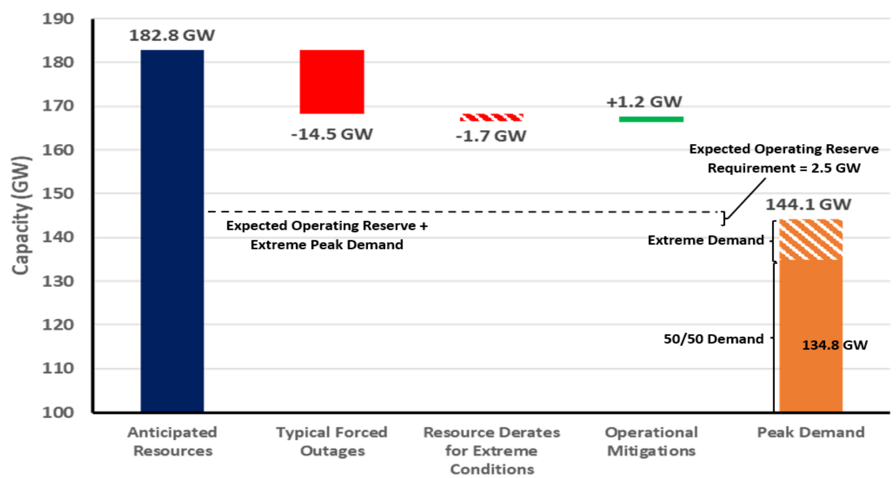
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Based on historical data and trending

Resource Derates for Extreme Conditions: Reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: accounts for an estimated value based on operational / emergency procedures

SERC-Central

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

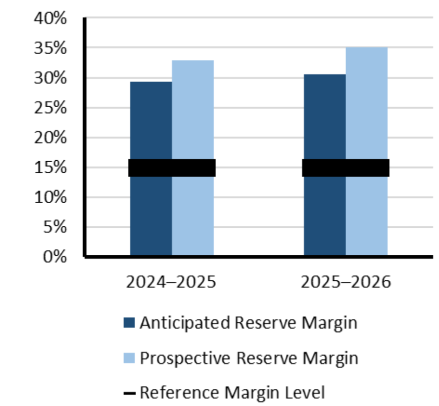
Highlights

- SERC-Central is transitioning from a summer-peaking area to a dual-peaking system.
- For the 2025–2026 Winter, SERC-Central projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Most entities across SERC-Central report that fuel security is strong since it is supported by firm natural gas contracts, storage resources, and reliable pipeline capacity. Coal inventories are projected to remain within operational ranges necessary to meet winter demand.
- Following lessons from Winter Storm Elliott, one SERC-Central entity raised its winter Planning Reserve Margin target to 26% and updated preparedness programs with improved heat trace capabilities.

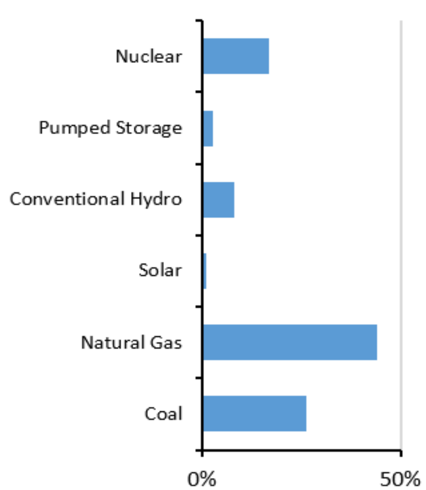
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand. A severe cold weather event that extends to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

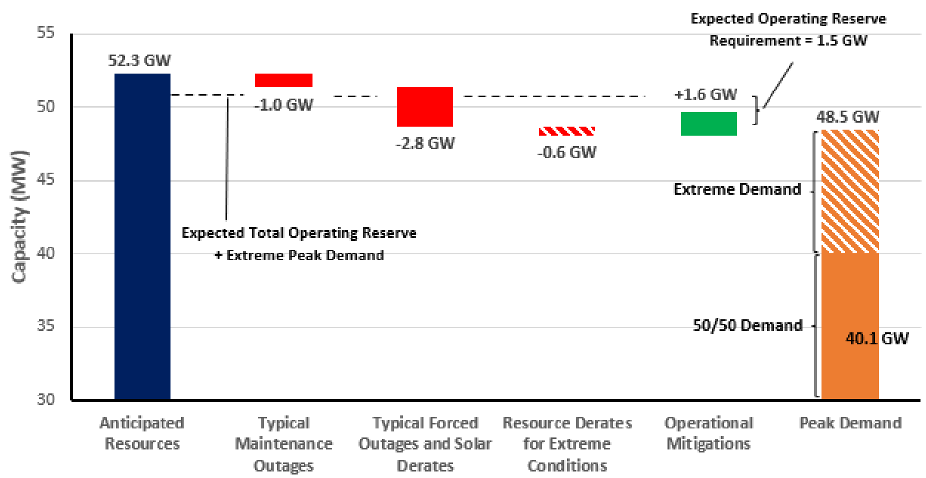
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Typical Maintenance Outages: Data collected through a survey of members for expected outages during December through February

Typical Forced Outages and Solar Derate: Includes any weighted average forced-outage rates on-peak that are not factored into the anticipated resources calculation . Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood extreme conditions

Operational Mitigations: A total of over 1.6 GW based on operational/emergency procedures

SERC-East

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

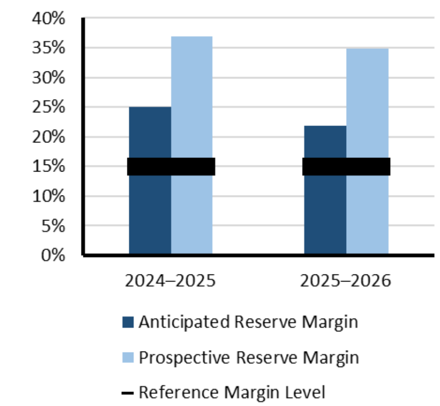
Highlights

- SERC-East is transitioning from a summer-peaking area to potentially peaking during both summer and winter. This shift is attributed to the continued addition of solar PV generation, which reduces summer peak demand, and a trend toward electrification of heating, which drives up winter peak demand.
- For the 2025–2026 Winter, the SERC-East region projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Fuel supplies and transportation remain stable, and entities anticipate maintaining adequate coal and oil inventories with no reported changes to fuel procurement or operator plans for the upcoming winter.
- Probabilistic Base Case Results (Median Weather): EUE is 61.95 MWh and LOLH is 0.06 hours/year. EUE values are likely due to higher winter peaks and/or lower supply of capacity that can meet early winter morning demand.
- Mitigation measures for extreme conditions include voltage reduction (25–50 MW) and load-shedding programs that cover up to 30% of system load.

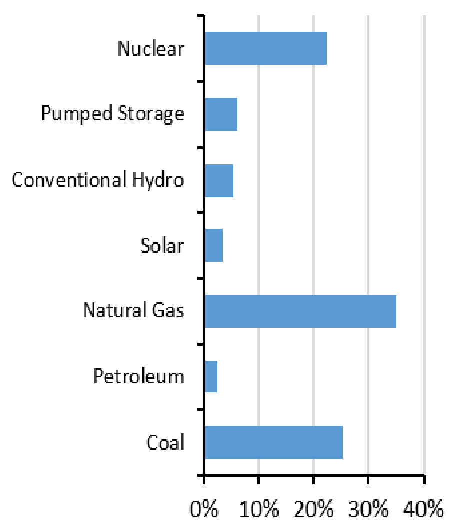
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal demand scenarios. A severe cold weather event extending to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

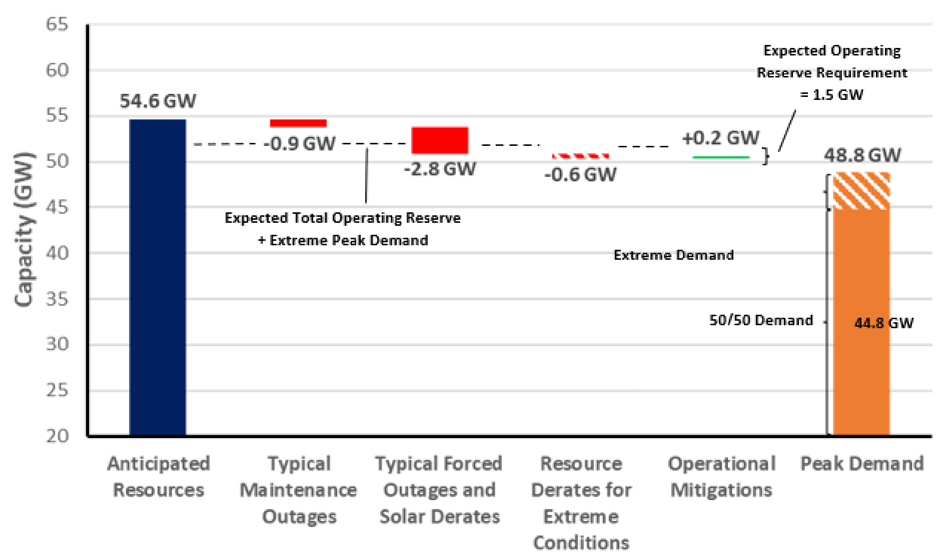
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages (excluding 2022–2025)

Operational Mitigations: A total of 0.2 GW based on operational/emergency procedures

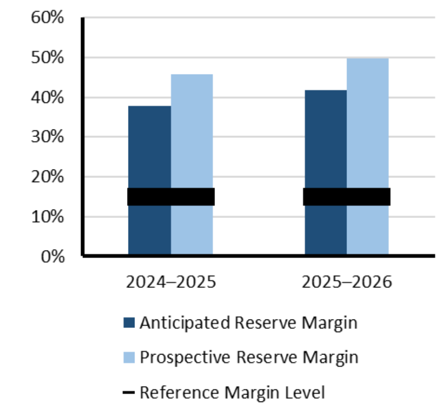
SERC-Florida Peninsula

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

Highlights

- SERC-Florida Peninsula is a summer-peaking assessment area.
- Florida Peninsula entities have not identified any emerging reliability issues for the upcoming 2025–26 Winter season with an ARM projected at 39%, well above the RML, while the 2024 NERC ProbA base-case results project a sufficient level of resources to serve the expected load under median weather and typical system operating conditions (EUE is 1.09 MWh and LOLH is 0.00 hours/year).
- Many entities report strong fuel security, supported by firm natural gas contracts, storage resources, reliable pipeline capacity, and actively managed coal and oil inventories, which are projected to remain within operational ranges to meet winter demand.
- Florida Peninsula entities do not assume non-firm external assistance from neighboring areas during extreme conditions.

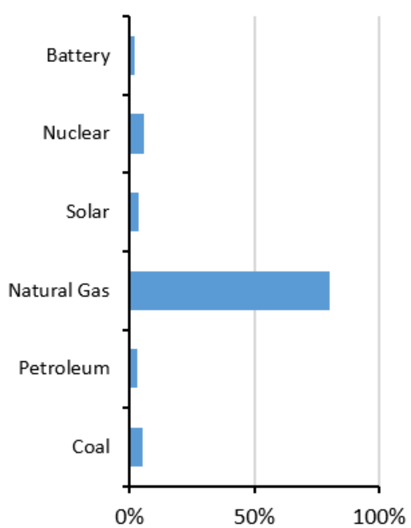
On-Peak Reserve Margin



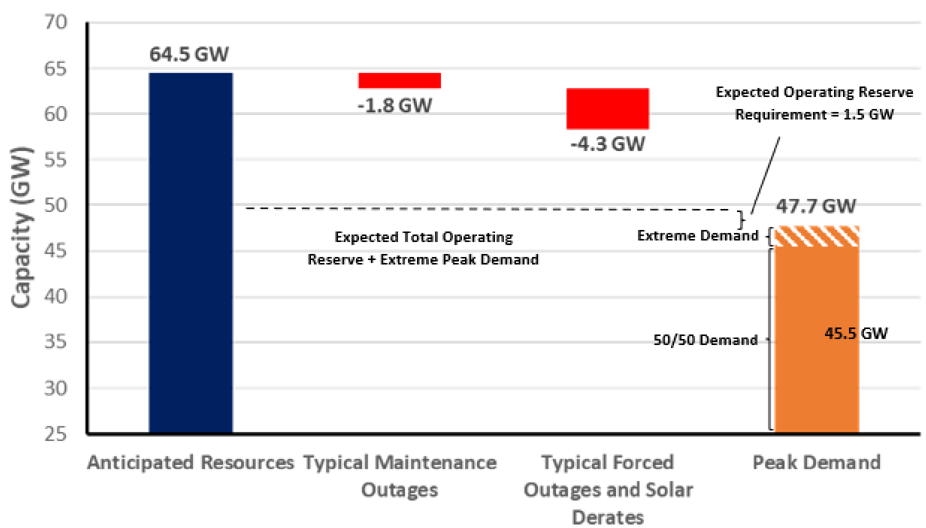
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood extreme conditions

SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

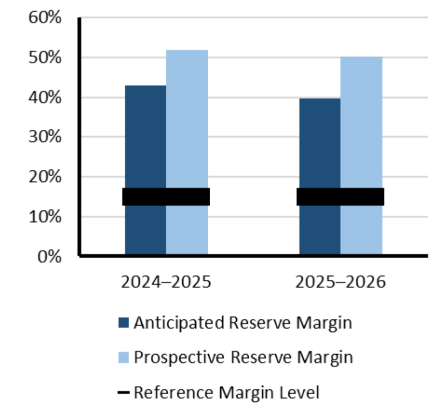
Highlights

- SERC-Southeast is trending towards becoming slightly winter-peaking.
- For the 2025–2026 Winter, SERC-Southeast entities report no emerging reliability concerns and expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories to serve the expected load under typical system operating conditions. The 2024 NERC ProbA base-case results in EUE and LOLH are both 0.00.
- While most SERC-Southeast BAs expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories, one BA highlights potential risks related to natural gas transportation capacity, citing high pipeline utilization, competition for delivered gas, and ratable flow requirements. Mitigation strategies include securing third-party gas supply, adding dual-fuel capability, and implementing coal inventory management.
- Entities have made refinements such as replacing specific 230 kV circuit breakers and increasing monitoring frequencies for critical plant systems after January 2025 winter events.

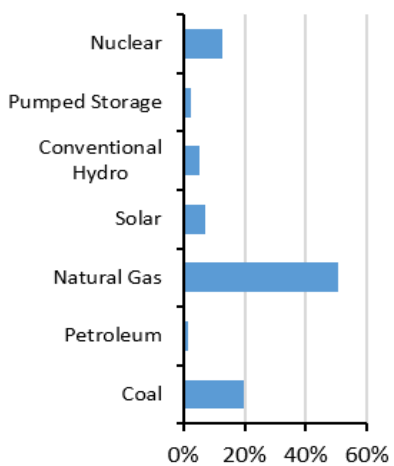
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

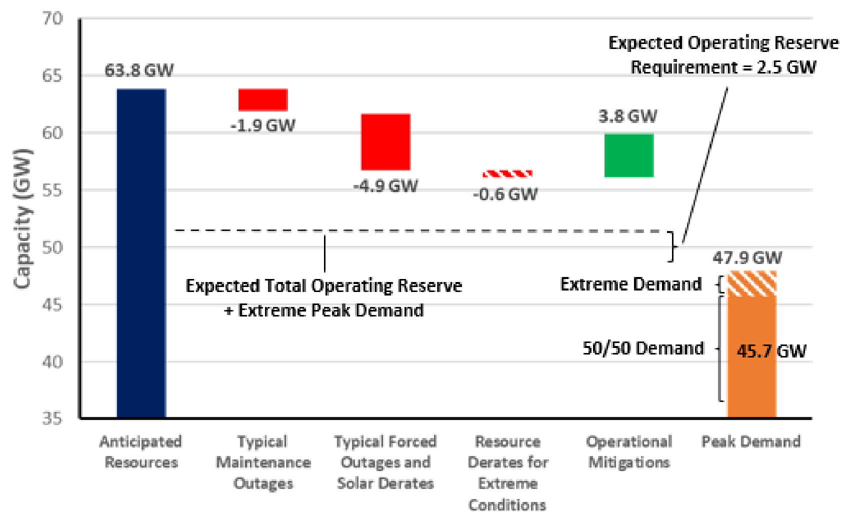
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages

Operational Mitigations: A total of 3.8 GW based on operational/emergency procedures

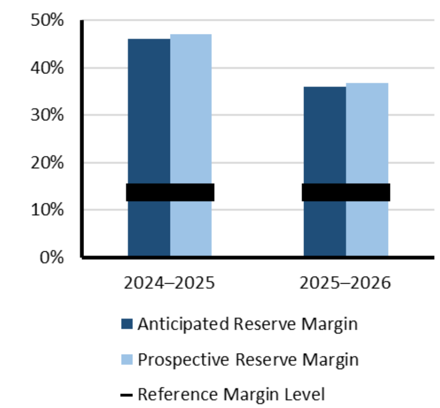
Texas RE-ERCOT

ERCOT is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking and covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas power grid.

Highlights

- Given expected system conditions, an ARM of 36% and RML of 13.75%, ERCOT expects to have sufficient operating reserves for the peak hour ending 8:00 a.m.
- ERCOT does not expect any significant fuel supply issues for the winter.
- ERCOT has conducted 2,028 generation resource and transmission service provider (TSP) winter weatherization inspections since Winter 2021–2022.
- Winter peak demands typically occur before sunrise and after sunset when solar generation is not available. Significant battery storage mitigates these risks.
- ERCOT's probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
- Increased load growth in west Texas combined with "no solar" and low wind conditions can cause transmission lines into this area to become heavily loaded. ERCOT has introduced improved dynamic line ratings that allow for greater transfers at colder temperatures and periods of low irradiance.

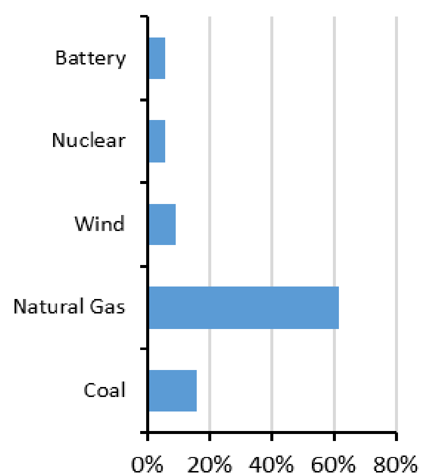
On-Peak Reserve Margin



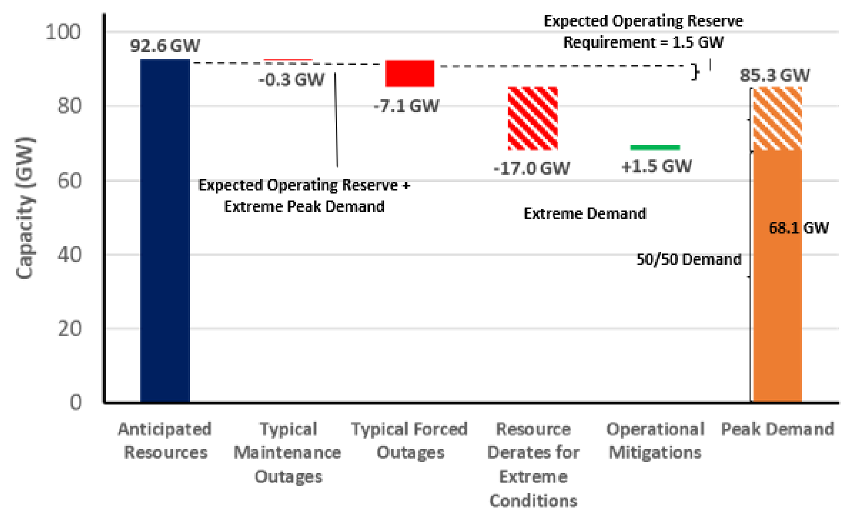
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Presumes weather conditions comparable to Winter Storm Uri. The adjustment is calculated as the difference between the 100th percentile and 50th percentile values from ERCOT's Probabilistic Reserve Risk Model (PRRM) simulated load outcome distribution for hour ending 8:00 a.m.

Typical Maintenance Outages: Based on historical winter data and consideration of ERCOT's allowed maximum system daily planned outage capacity

Typical Forced Outages: Based on a probability distribution created using historical ERCOT Outage Scheduler data for the last three Januarys.

Resource Derates for Extreme Conditions: Weather-related thermal and wind outages based on Winter Storm Uri levels, adjusted for reductions due to weatherization standards. Also includes high non-weather-related outages.

Operational Mitigations: Additional potential capacity from switchable generation and imports

WECC-Alberta

WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province's Planning Entity and RC responsible for safe, reliable, and economic operation of the Alberta Interconnected Electric System. AESO is a non-profit corporation that operates a system that includes approximately 26,000 kilometers of transmission lines and connects approximately 426 qualified generating units and nearly 250 market participants through a wholesale market. Alberta's transmission system has three interties with neighboring areas: Saskatchewan (see MRO-SaskPower), British Columbia (see WECC-British Columbia), and Montana (see WECC-Northwest). Peak electricity demand on the AESO system currently occurs during the winter season.

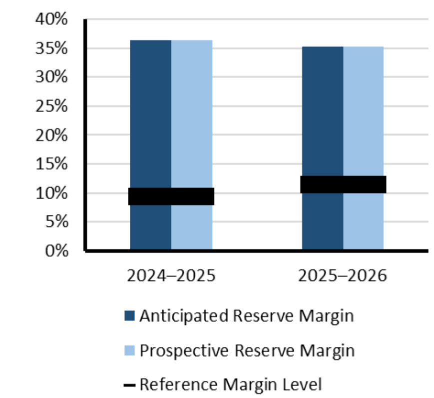
Highlights

- At an extreme winter peak of 12,982 MW, with extreme forced outages at 530 MW and derates for extreme conditions bringing wind energy availability down by 1,800 MW and hydroelectricity by 88 MW, the required reserves are 759 MW and are sufficiently met, even with low availability.
- Demand is expected to increase 1.1% from last winter with the existing-certain installed capacity having increased 23%.
- Solar availability is down because 1,000 MW of PV moved from originally expecting to come on-line in 2024 as Tier 1 resources to Tier 2s mostly anticipated to come on-line in 2025, but with less certainty.

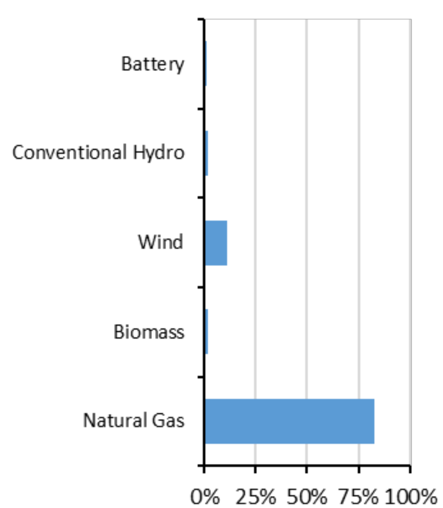
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

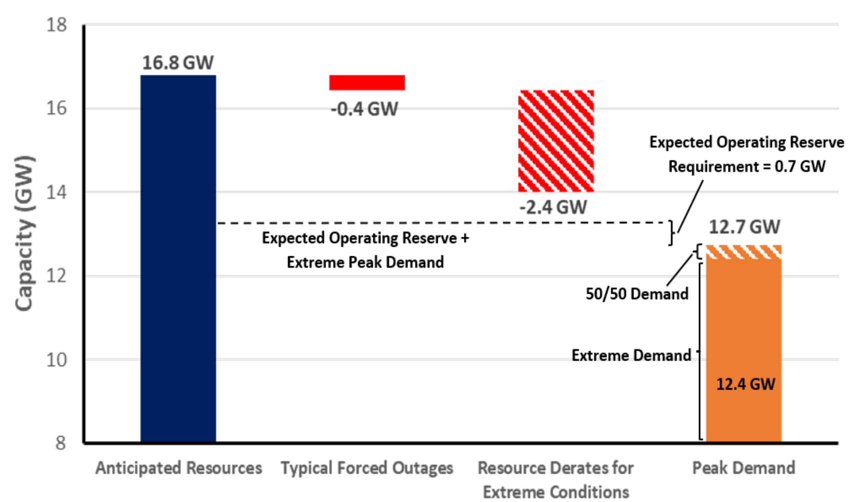
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



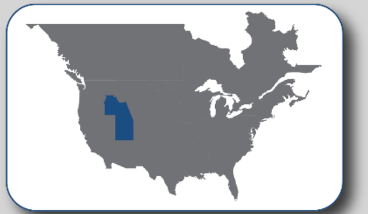
Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS data

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern BA area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025-26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

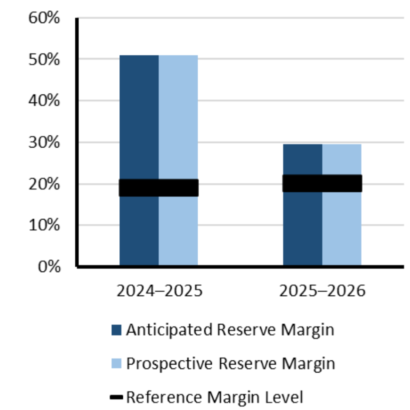
Highlights

- At an extreme winter peak of 11.1 GW under an extreme combination of derates and outages, the region could be short 1.0 GW before imports and is expected to need to rely on transfers.
- Net internal demand is expected to increase 1% since last year, with total internal demand up 1.8% being offset by a doubling of controllable and dispatchable demand response.
- Tier 1 resources have declined and do not appear to be offset by increases in existing-certain generation resource capacity. Nameplate wind has increased by almost 18% and solar by almost 30%. Hydro is also up over 7% in total installed capacity.
- Reliance on imports is expected to be required to maintain resource adequacy during extreme peak demand and extreme derate conditions.

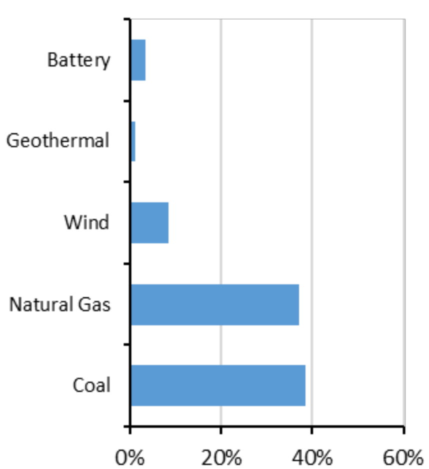
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

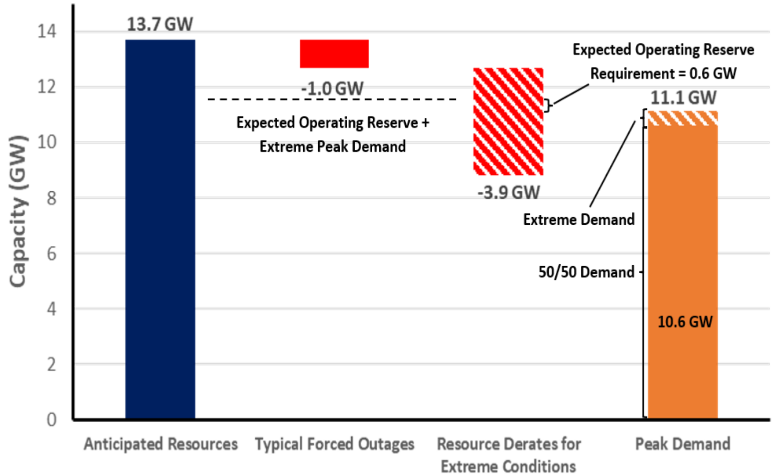
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Extreme Derates: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

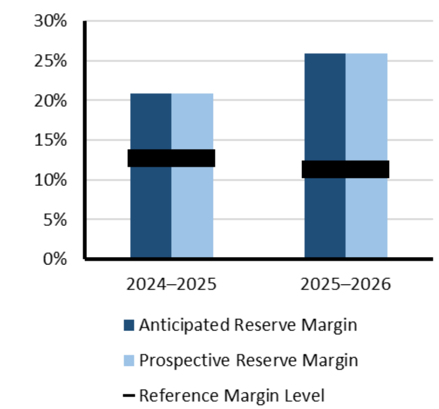
WECC-British Columbia

WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and RC for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia BES and its interconnections. BC Hydro operates an integrated system supported by 30 hydroelectric plants, approximately 80,000 kilometers of transmission and distribution lines, and 125 contracts with independent power producers. BC Hydro's transmission system has two interties with neighboring areas: the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta). Peak electricity demand on the BC Hydro system currently occurs during winter.

Highlights

- Peak demand is expected to remain about the same as last winter.
- There are about 200 MW more (47%) planned Tier 1 resources for this winter than last.
- Solar nameplate capacity has increased from 2 MW to 17 MW since last winter and hydroelectric nameplate capacity is up more than 5%, or 1,366 MW.

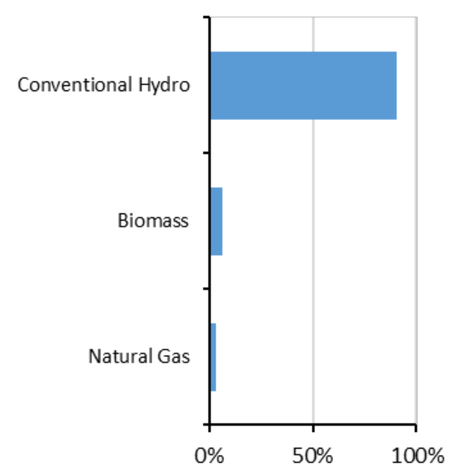
On-Peak Reserve Margin



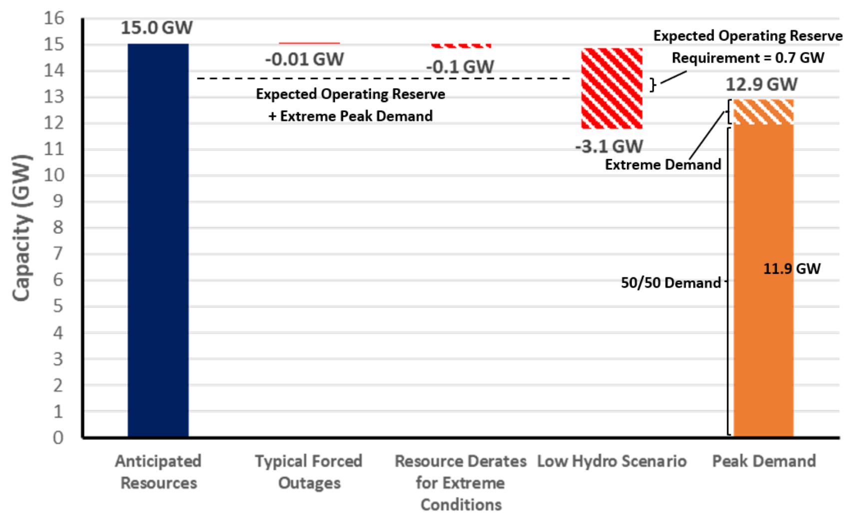
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme demand scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

Low Hydro Scenario: Estimated derate for lower hydro output

WECC-California

WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, the Los Angeles Department of Water and Power, the Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

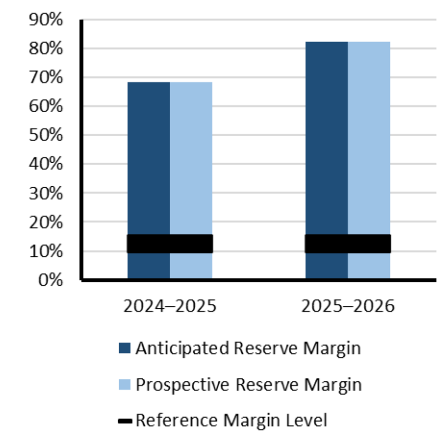
Highlights

- Operating reserve margins are met before imports in all winter resource availability scenarios.
- On-peak demand is expected to remain about the same as last winter. Demand-side management is down about 10%.
- Existing-certain capacity is up almost 5%, while planned Tier 1 resources are up more than 2 GW. The total wind nameplate capacity is up almost 27% and solar almost 13%. Hydro is down 4%.
- No reliance on imports is expected to be required to maintain resource adequacy for Winter 2025–2026.

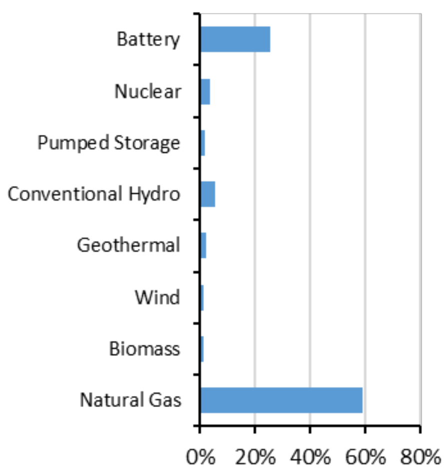
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

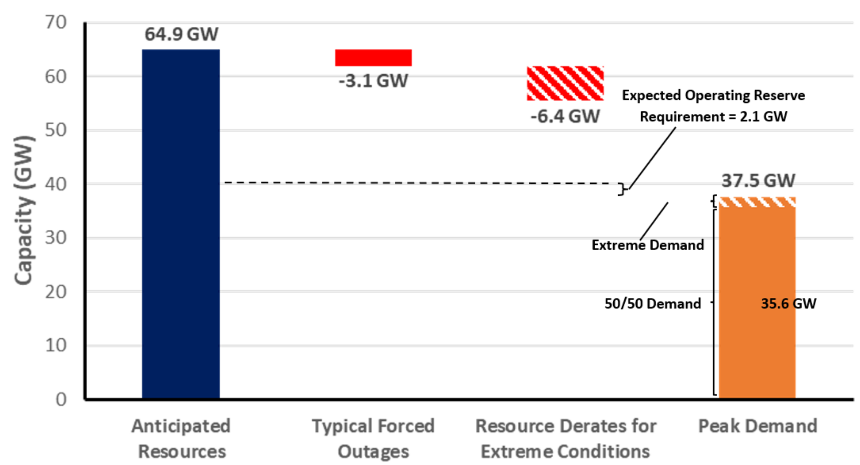
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

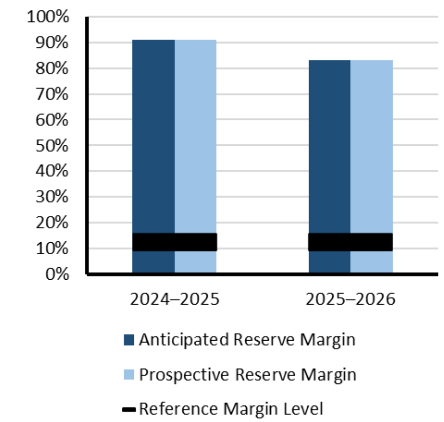
Highlights

- As a summer-peaking region, operating reserve margins are met before imports in all scenarios.
- Planned Tier 1 resources are down 100% to zero as expected resources have either been brought on-line to move into existing or, in the case of some natural gas, have been delayed until 2026 and moved into Tier 2.
- The existing-certain on peak reserve margin is down by 5.2%, and the anticipated and prospective reserve margins are down by 7.8%; however, since Mexico is heavily summer-peaking, the 83% reserve margin still exceeds the RML of 12.5%, which remains unchanged.

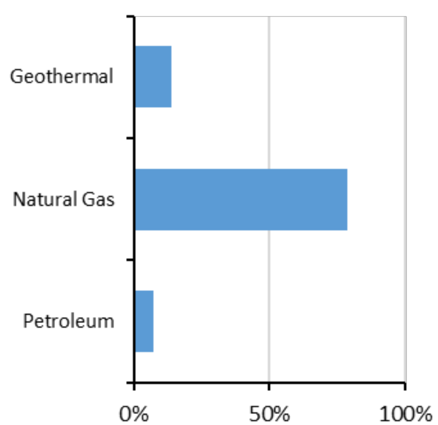
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

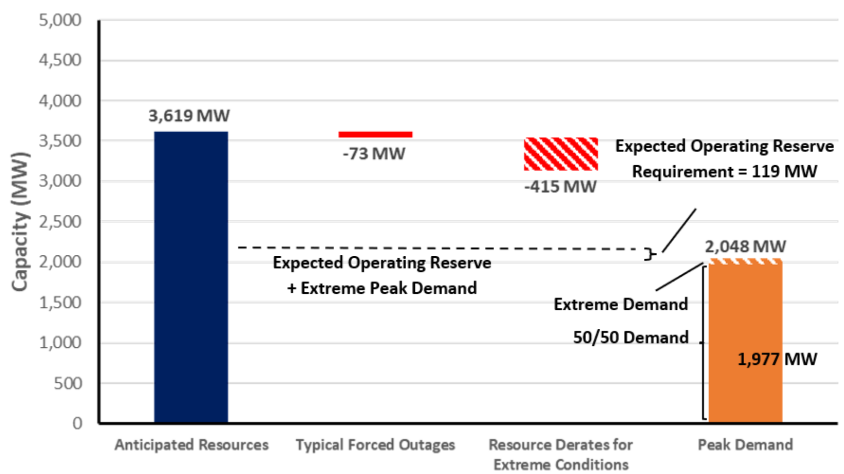
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



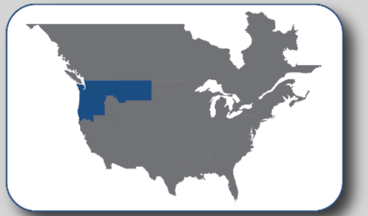
Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



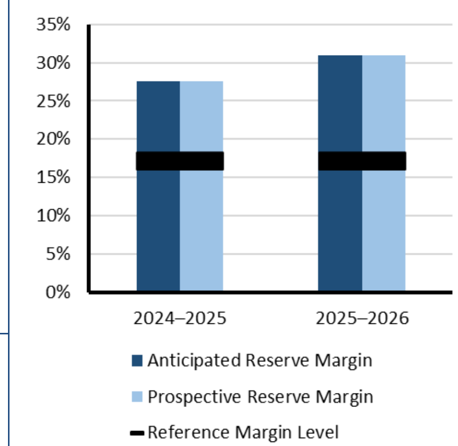
WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

Highlights

- The Northwest has historically been a mixed season-peaking region.
- Operating reserve margins are expected to be met after imports in all winter scenarios.
- Total and net internal demand are up 9.3% with the primary drivers being data centers, residential electrification, transportation electrification, and semiconductor manufacturing.
- Large coal unit retirements and conventional hydro unit retirements are attributable to the reduction in existing certain capacity of 10.5%; however, planned Tier 1 resources have soared over 580%, from 463 MW to over 3 GW.
- Nameplate wind capacity is up over 3 GW (26%) and solar nameplate capacity is up nearly 2,690 MW (134%), which has also increased the solar availability on the peak hour.
- An increase in firm imports is seen in the model, 6.1 GW, absorbing the reduction in existing certain capacity of 4 GW.

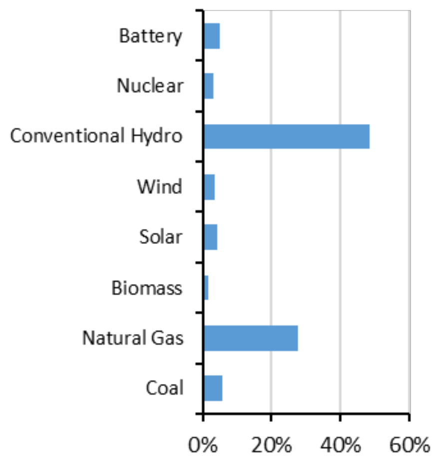
On-Peak Reserve Margin



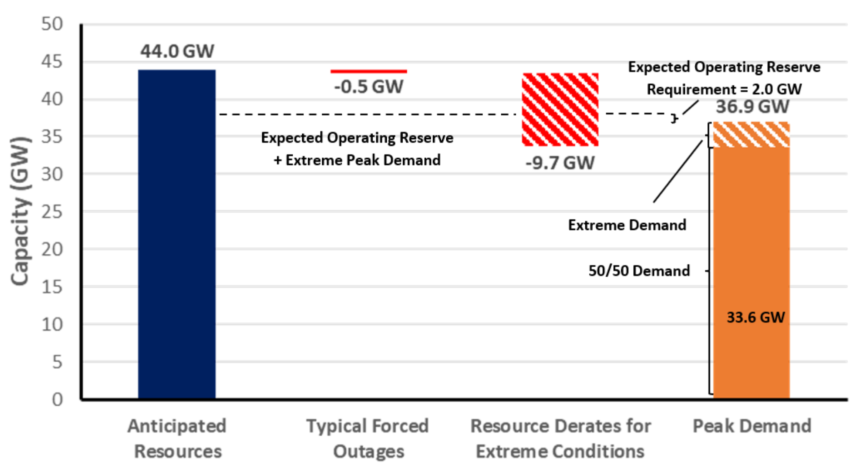
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



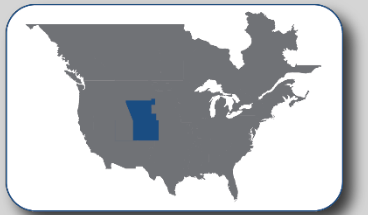
Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period. This value includes 6.8 GW of hydro derates.



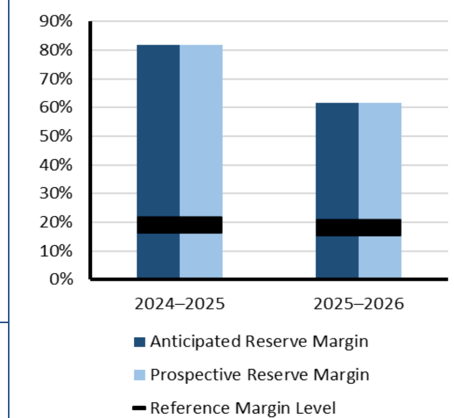
WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

Highlights

- In Rocky Mountain, operating reserve margins are expected to be met before imports in all winter scenarios.
- Total and net internal demand are up almost 1%. The primary drivers are data centers and commercial and industrial customer growth.
- Planned Tier 1 resources are up over 84%, from almost 200 MW to over 365 MW. Solar nameplate capacity is up 27%; however, on-peak solar energy availability is down 100% due to the shift to after sunset. Expected hydro on peak energy availability is also down by around a quarter on the peak hour. Existing-Certain, Anticipated, and Prospective Reserve Margins are all down by over 20% on the peak hour; however, the region still maintains resource adequacy with margins hovering around 60% compared to the RML of 18%.
- No reliance on imports is expected to be required to maintain resource adequacy under combined extreme peak and extreme derated conditions.

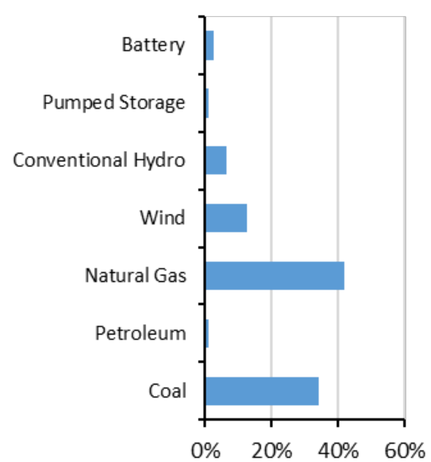
On-Peak Reserve Margin



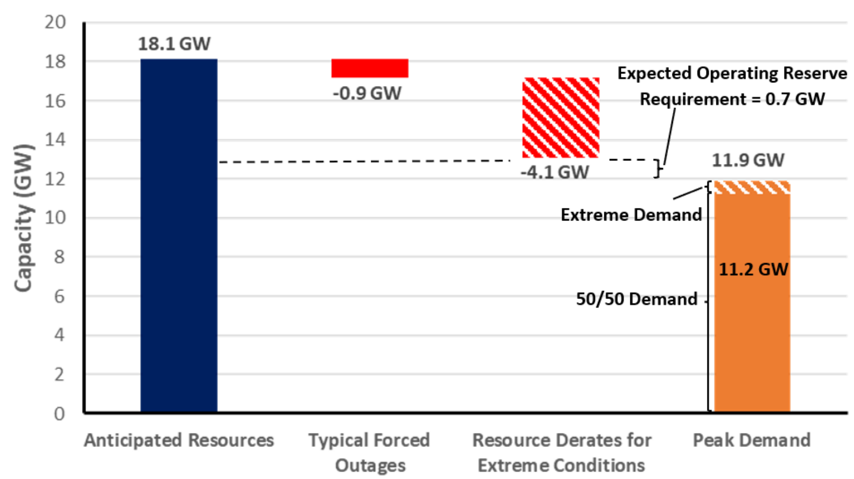
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



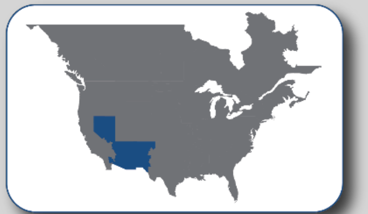
Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

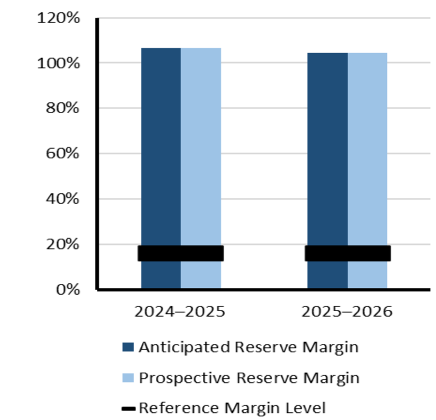
Highlights

- The Southwest is anticipated to be resource adequate under all winter expected and extreme energy availability and demand scenarios before imports.
- Total internal demand is expected to be up 1.5% and net internal demand up 2.3% since last winter. The primary drivers for load growth are data centers and industrial and residential electrification. Controllable and dispatchable demand response is down nearly half, by 163 MW.
- Planned Tier 1 resources are down over 19% as some have moved into existing certain, which is up almost 3%, over 1 GW, and other projects have experienced delays.
- Wind nameplate is up 12%, 470 MW, correlating to on-peak energy availability from wind increasing almost 11%, by 114 MW, while solar nameplate is up 27% or over 2.5 GW.

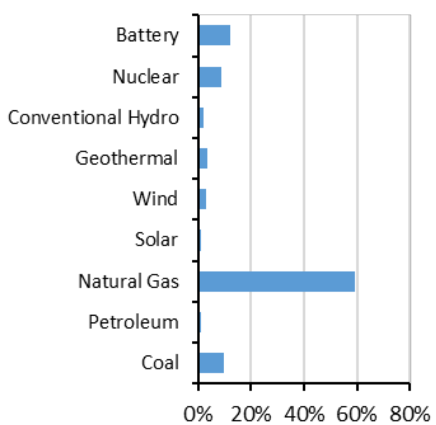
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

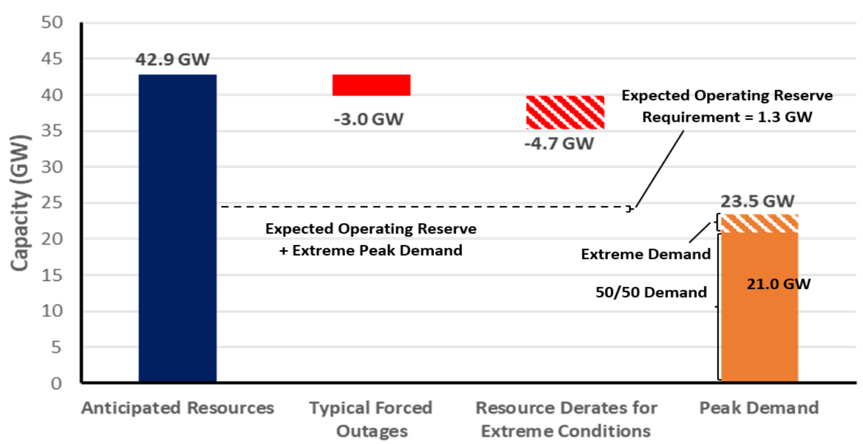
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[11] or total internal demand for the summer and winter of each year.[12]
• Total internal demand projections are based on normal weather (50/50 distribution)[13] and are provided on a coincident[14] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (VER) (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: **Existing-Other Capacity**: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

[11] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[12] The summer season represents June–September and the winter season represents December–February.

[13] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[14] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources, and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The ARM, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[15] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. NPCC-Maritimes marginally does not meet its RML for the upcoming winter. Other than NPCC-Maritimes, all assessment areas have sufficient ARMs to meet or exceed their RML for the 2025 winter as shown in **Figure 4**.

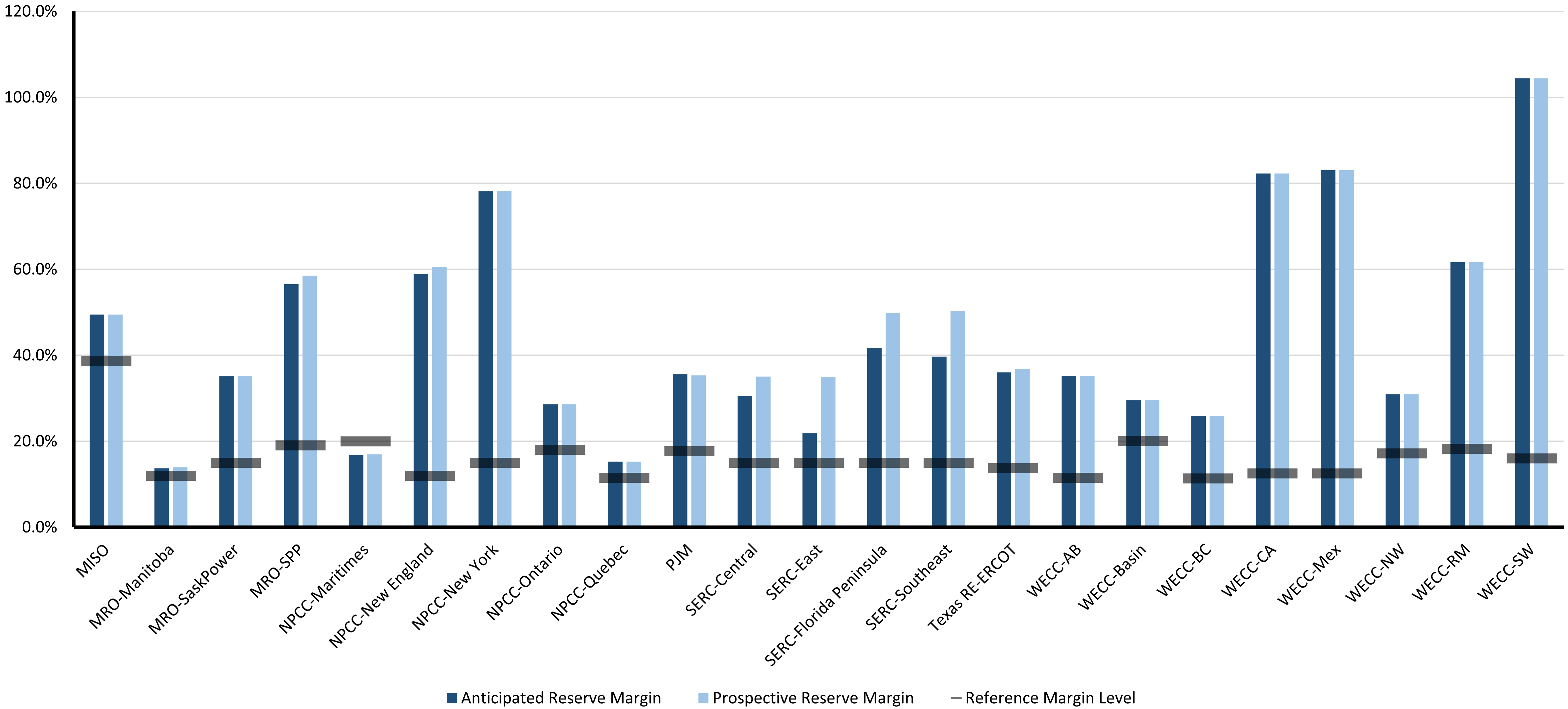


Figure 4: Winter 2025–2026 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[15] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast ARMs from the 2024–2025 Winter to the 2025–2026 Winter. All areas except NPCC-Maritimes remain above their RMLs for 2025–2026 Winter. The Canadian winter-peaking systems, which include MRO-Manitoba, MRO-SaskPower, NPCC-Maritimes, NPCC-Québec, WECC-Alberta, and WECC-British Columbia, may have reserve margins that are near RMLs but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the Data Concepts and Assumptions section.

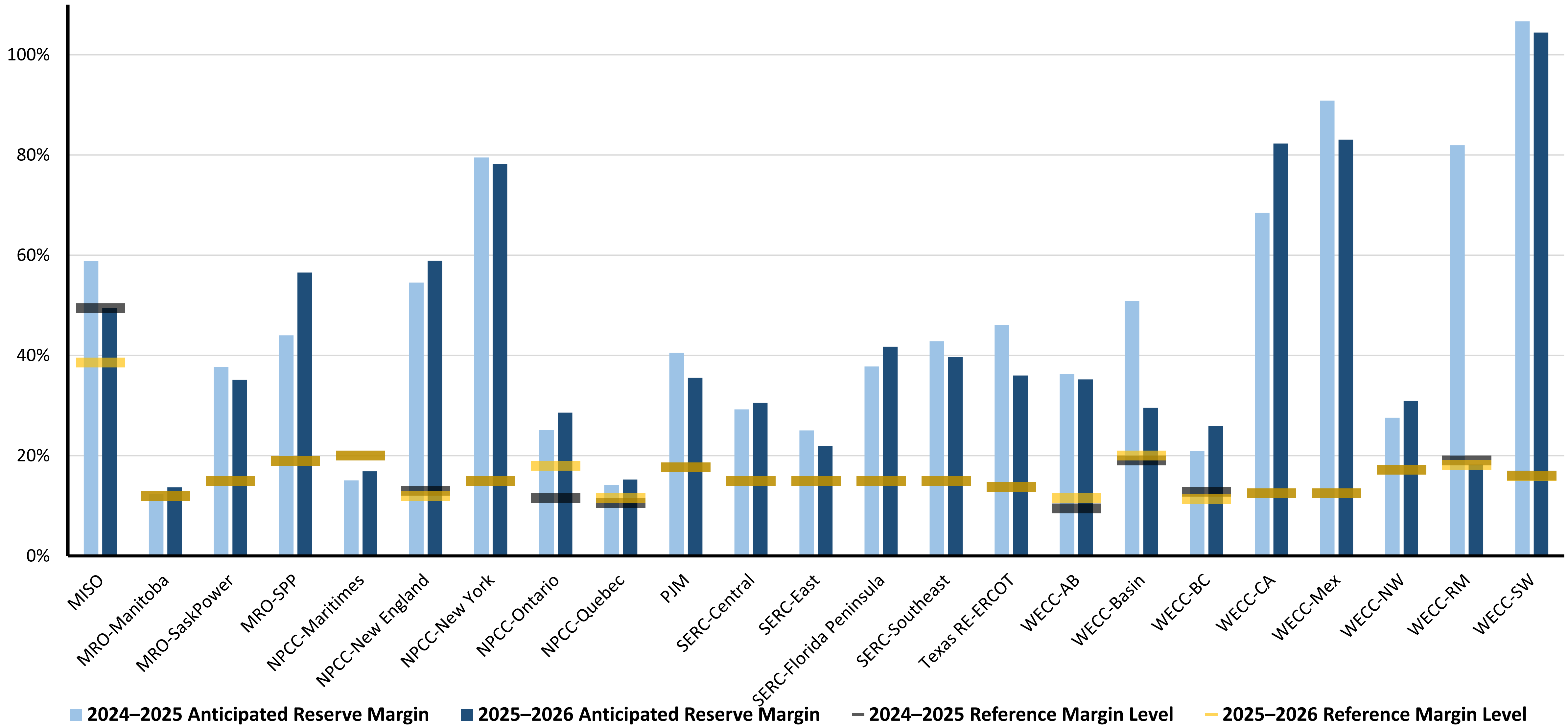


Figure 5: Winter 2024–2025 and Winter 2025–2026 Anticipated Reserve Margins Year-to-Year Change

Demand and Resource Tables

Peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area are as follows in each table.

MISO			
Demand, Resource, and Reserve Margins	**2024–2025 WRA[16]**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	102,353	105,249	2.8%
Demand Response: Available	6,219	8,250	32.7%
Net Internal Demand	96,134	96,999	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	150,407	142,880	-5.0%
Tier 1 Planned Capacity	122	0	0.0%
Net Firm Capacity Transfers	2,310	2,113	-8.5%
Anticipated Resources	152,717	144,993	-5.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	152,839	144,993	-5.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	58.9%	49.5%	-9.4
Prospective Reserve Margin	59.0%	49.5%	-9.5
Reference Margin Level	49.4%	38.6%	-10.8

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,788	47,168	3.0%
Demand Response: Available	1,128	1,091	-3.3%
Net Internal Demand	45,926	46,077	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	67,252	71,074	5.7%
Tier 1 Planned Capacity	0	1087	0.0%
Net Firm Capacity Transfers	-1,116	-32	-97.1%
Anticipated Resources	66,136	72,129	9.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	66,090	73,029	10.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.0%	56.5%	12.5
Prospective Reserve Margin	43.9%	58.5%	14.6
Reference Margin Level	19.0%	19.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,852	3,944	2.4%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,802	3,894	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,946	4,972	0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	5,236	5,262	0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,236	5,262	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.7%	35.1%	-2.6
Prospective Reserve Margin	37.7%	35.1%	-2.6
Reference Margin Level	15.0%	15.0%	0.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,814	4,903	1.8%
Demand Response: Available	0	0	0.0%
Net Internal Demand	4,814	4,903	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,924	5,688	-4.0%
Tier 1 Planned Capacity	10	0	-100.0%
Net Firm Capacity Transfers	-527	-113	-78.5%
Anticipated Resources	5,407	5,575	3.1%
Existing-Other Capacity	18	13	-26.8%
Prospective Resources	5,425	5,588	3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.3%	13.7%	1.4
Prospective Reserve Margin	12.7%	14.0%	1.3
Reference Margin Level	12.0%	12.0%	0.0

[16] MISO-provided updated data post 2024-25 WRA publication.

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	6,167	6,061	-1.7%
Demand Response: Available	259	248	-4.4%
Net Internal Demand	5,907	5,813	-1.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,647	6,704	0.9%
Tier 1 Planned Capacity	6	88	0.0%
Net Firm Capacity Transfers	145	1	-99.0%
Anticipated Resources	6,798	6,794	-0.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	6,798	6,800	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.1%	16.9%	1.8
Prospective Reserve Margin	15.1%	17.0%	1.9
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,651	20,056	-2.9%
Demand Response: Available	343	440	28.2%
Net Internal Demand	20,308	19,616	-3.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	30,030	29,935	-0.3%
Tier 1 Planned Capacity	194	0	-100.0%
Net Firm Capacity Transfers	1,161	1,235	6.4%
Anticipated Resources	31,385	31,170	-0.7%
Existing-Other Capacity	306	322	5.2%
Prospective Resources	31,691	31,492	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	54.5%	58.9%	4.4
Prospective Reserve Margin	56.1%	60.5%	4.5
Reference Margin Level	13.0%	12.0%	-1.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	23,800	24,200	1.7%
Demand Response: Available	802	1,027	28.1%
Net Internal Demand	22,998	23,173	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,522	40,080	-1.1%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	759	1,203	58.5%
Anticipated Resources	41,281	41,283	0.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	41,281	41,283	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	79.5%	78.2%	-1.3
Prospective Reserve Margin	79.5%	78.2%	-1.3
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,898	22,013	0.7%
Demand Response: Available	915	868	-5.2%
Net Internal Demand	20,982	21,146	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,652	27,319	2.5%
Tier 1 Planned Capacity	0	294	#DIV/0!
Net Firm Capacity Transfers	-450	-420	-6.7%
Anticipated Resources	26,202	27,193	3.8%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	26,202	27,193	3.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.1%	28.6%	3.5
Prospective Reserve Margin	25.1%	28.6%	3.5
Reference Margin Level	11.5%	18.0%	6.5

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,512	40,799	0.8%
Demand Response: Available	4,451	4,902	10.9%
Net Internal Demand	36,061	35,897	-0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	41,560	41,698	0.3%
Tier 1 Planned Capacity	73	61	0.0%
Net Firm Capacity Transfers	-479	-390	-18.6%
Anticipated Resources	41,154	41,368	0.5%
Existing-Other Capacity	-479	0	0.0%
Prospective Resources	41,154	41,368	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	15.2%	1.1
Prospective Reserve Margin	14.1%	15.2%	1.1
Reference Margin Level	10.5%	11.5%	1.0

SERC-Central			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,895	42,875	0.0%
Demand Response: Available	1,497	2,809	87.6%
Net Internal Demand	41,397	40,067	-3.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,578	50,454	-2.2%
Tier 1 Planned Capacity	0	0	0%
Net Firm Capacity Transfers	1,922	1,847	-3.9%
Anticipated Resources	53,500	52,301	-2.2%
Existing-Other Capacity	1,498	1,810	20.8%
Prospective Resources	54,998	54,111	-1.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.2%	30.5%	1.3
Prospective Reserve Margin	32.9%	35.1%	2.2
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	136,328	140,827	3.3%
Demand Response: Available	5,616	5,998	6.8%
Net Internal Demand	130,712	134,829	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	179,216	178,335	-0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	4,502	4,448	-1.2%
Anticipated Resources	183,718	182,783	-0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	183,718	182,452	-0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	40.6%	35.6%	-5.0
Prospective Reserve Margin	40.6%	35.3%	-5.2
Reference Margin Level	17.7%	17.7%	-12.3

SERC-East			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,005	45,703	1.6%
Demand Response: Available	982	888	-9.6%
Net Internal Demand	44,023	44,815	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	54,379	54,460	0.1%
Tier 1 Planned Capacity	72	11	-84.3%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	55,045	54,622	-0.8%
Existing-Other Capacity	5,209	5,832	12.0%
Prospective Resources	60,254	60,453	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.0%	21.9%	-3.2
Prospective Reserve Margin	36.9%	34.9%	-2.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,494	48,628	0.3%
Demand Response: Available	2,780	3,127	12.5%
Net Internal Demand	45,714	45,501	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,579	63,502	1.5%
Tier 1 Planned Capacity	15	692	4510.0%
Net Firm Capacity Transfers	400	300	-25.0%
Anticipated Resources	62,994	64,494	2.4%
Existing-Other Capacity	3,673	3,671	0.0%
Prospective Resources	66,667	68,165	2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.8%	41.7%	3.9
Prospective Reserve Margin	45.8%	49.8%	4.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,308	47,056	3.9%
Demand Response: Available	1,638	1,365	-16.7%
Net Internal Demand	43,670	45,691	4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,805	63,339	0.9%
Tier 1 Planned Capacity	765	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	62,378	63,828	2.3%
Existing-Other Capacity	3,920	4,847	23.7%
Prospective Resources	66,298	68,675	3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.8%	39.7%	-3.1
Prospective Reserve Margin	51.8%	50.3%	-1.5
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	73,193	77,387	5.7%
Demand Response: Available	5,447	9,330	71.3%
Net Internal Demand	67,746	68,057	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	98,712	89,977	-8.8%
Tier 1 Planned Capacity	239	1351	464.9%
Net Firm Capacity Transfers	20	1,235	6075.0%
Anticipated Resources	98,971	92,562	-6.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	99,691	93,137	-6.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	46.1%	36.0%	-10.1
Prospective Reserve Margin	47.2%	36.9%	-10.3
Reference Margin Level	13.75%	13.8%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,280	12,411	1.1%
Demand Response: Available	0	0	0.0%
Net Internal Demand	12,280	12,411	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,535	16,658	23.1%
Tier 1 Planned Capacity	3206	124	-96.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	16,740	16,782	0.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	16,740	16,782	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.3%	35.2%	-1.1
Prospective Reserve Margin	36.3%	35.2%	-1.1
Reference Margin Level	9.5%	11.5%	2.0

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,568	10,758	1.8%
Demand Response: Available	85	170	100.0%
Net Internal Demand	10,483	10,588	1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,213	13,183	-0.2%
Tier 1 Planned Capacity	2,605	533	-79.5%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	15,817	13,717	-13.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	15,817	13,717	-13.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	50.9%	29.6%	-21.3
Prospective Reserve Margin	50.9%	29.6%	-21.3
Reference Margin Level	19.0%	20.0%	1.0

WECC-CA			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	36,441	36,281	-0.4%
Demand Response: Available	743	666	-10.4%
Net Internal Demand	35,698	35,615	-0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,380	57,923	4.6%
Tier 1 Planned Capacity	4,757	6,997	47.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	60,138	64,920	8.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	60,138	65,920	8.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	68.5%	82.3%	13.8
Prospective Reserve Margin	68.5%	82.3%	13.8
Reference Margin Level	12.5%	12.5%	0.0

WECC-BC			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,966	11,936	-0.3%
Demand Response: Available	0	0	0.0%
Net Internal Demand	11,966	11,936	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,870	14,389	3.7%
Tier 1 Planned Capacity	433	637	47.0%
Net Firm Capacity Transfers	164	0	-100.0%
Anticipated Resources	14,467	15,026	3.9%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	14,467	15,026	3.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.9%	25.9%	5.0
Prospective Reserve Margin	20.9%	25.9%	5.0
Reference Margin Level	12.8%	11.4%	-1.5

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	1,983	1,977	-0.3%
Demand Response: Available	0	0	0%
Net Internal Demand	1,983	1,977	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,733	3,619	-3.0%
Tier 1 Planned Capacity	52	0	-100.0%
Net Firm Capacity Transfers	0	0	0%!
Anticipated Resources	3,784	3,619	-4.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	3,784	3,619	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	90.8%	83.1%	-7.8
Prospective Reserve Margin	90.8%	83.1%	-7.8
Reference Margin Level	12.5%	12.5%	0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	30,748	33,604	9.3%
Demand Response: Available	30	30	0.0%
Net Internal Demand	30,718	33,574	9.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	38,729	34,671	-10.5%
Tier 1 Planned Capacity	463	3,152	581.5%
Net Firm Capacity Transfers	0	6,136	100%!
Anticipated Resources	39,192	43,959	12.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	39,192	43,959	12.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	30.9%	3.3
Prospective Reserve Margin	27.6%	30.9%	3.3
Reference Margin Level	17.2%	17.2%	0.0

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,481	11,501	9.7%
Demand Response: Available	282	285	1.1%
Net Internal Demand	10,199	11,216	10.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	18,356	17,768	-3.2%
Tier 1 Planned Capacity	199	366	84.3%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	18,555	18,134	-2.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	18,555	18,134	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	81.9%	61.7%	-20.3
Prospective Reserve Margin	81.9%	61.7%	-20.3
Reference Margin Level	19.0%	18.2%	-0.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,844	21,147	1.5%
Demand Response: Available	340	177	-47.9%
Net Internal Demand	20,504	20,970	2.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	38,991	40,135	2.9%
Tier 1 Planned Capacity	3,381	2,733	-19.2%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	42,372	42,868	1.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	42,372	42,868	1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	106.6%	104.4%	-2.2
Prospective Reserve Margin	106.6%	104.4%	-2.2
Reference Margin Level	16.0%	16.0%	0.0

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity and may vary widely year to year based on the identified risk hour. In many areas, winter demand peaks in the early morning hours or early evening resulting in little or no electrical resource output from solar PV resources and wide variability in wind availability. The following table shows the capacity contribution of existing wind and solar PV resources at the identified risk hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS.

BPS Variable Energy Resources On-Peak Capacity Contributions by Assessment Area

	Wind			Solar			Run of River Hydro		
Assessment Area/Interconnection (* - includes all hydro)	Nameplate Wind (MW)	Expected Wind (MW)	Expected Share of Nameplate (%)	Nameplate Solar PV (MW)	Expected Solar (MW)	Expected Share of Nameplate (%)	Nameplate Hydro (MW)	Expected Hydro (MW)	Expected Share of Nameplate (%)
MISO	30,247	8,772	29%	13,726	686	5%	2,351	1,404	60%
MRO-Manitoba Hydro	259	52	20%	0	0	0%	202	0	0%
MRO-SaskPower	816	433	53%	30	0	13%	884	703	80%
MRO-SPP	35,714	7,198	20%	1,197	457	38%	114	72	63%
NPCC-Maritimes	1,635	241	15%	155	10	6%	1,357	1,283	95%
NPCC-New England	2,675	455	17%	3,620	0	0%	3,742	1,453	39%
NPCC-New York	2,586	737	29%	627	0	0%	974	596	61%
NPCC-Ontario	4,943	1,971	40%	478	0	0%	0	0	0%
NPCC-Québec	4,024	1,426	35%	10	0	0%	445	445	100%
PJM*	13,318	5,463	41%	15,732	1	0%	8,134	7,900	97%
SERC-Central	1,324	370	28%	1,576	455	29%	4,991	4,027	81%
SERC-East	0	0	0%	7,068	1,792	25%	3,010	2,951	98%
SERC-Florida Peninsula	0	0	0%	12,058	2,151	18%	0	0	0%
SERC-Southeast	0	0	0%	8,670	4,461	51%	3,258	3,258	100%
Texas RE-ERCOT	40,629	7,833	19%	35,609	660	2%	579	566	98%
WECC-AB*	5,712	1,919	34%	2,206	0	0%	894	285	32%
WECC-Basin*	5,932	1,148	19%	3,853	62	2%	2,667	1,473	55%
WECC-BC*	747	85	11%	17	0	0%	17,752	13,560	76%
WECC-CA*	9,382	682	7%	28,328	0	0%	15,740	4,572	29%
WECC-Mex	40	4	11%	350	0	0%	0	0	0%
WECC-NW*	14,744	1,319	9%	4,695	1,556	33%	32,915	18,502	56%
WECC-RM*	5,681	2,265	40%	3,521	0	0%	3,251	1,327	41%
WECC-SW*	4,303	1,182	27%	12,139	391	3%	3,117	948	30%
EASTERN INTERCONNECTION	93,517	25,692	27%	64,937	10,013	15%	29,017	23,647	81%
QUÉBEC INTERCONNECTION	4,024	1,426	35%	10	0	0%	445	445	100%
TEXAS INTERCONNECTION	40,629	7,833	19%	35,609	660	2%	579	566	98%
WECC INTERCONNECTION	46,541	8,605	19%	55,108	2,008	4%	76336	40667	53%
INTERCONNECTION TOTAL:	**184,711**	**43,556**	**23%**	**155,664**	**12,685**	**8%**	106,377	65,325	61%

Review of Winter 2024–2025 Capacity and Energy Performance

The meteorological winter across the contiguous United States had an average temperature of 34.1 degrees F—1.9 degrees above average—ranking in the warmest third of NOAA's historical record. Total winter precipitation in the US was 5.87 inches, 0.92 of an inch below average, ranking in the driest third of the December–February climate record.[17] Most of Canada experienced temperatures at least 2°C above the baseline average with the Maritime provinces, southern Ontario, and the Canadian west coast recording temperature departures nearer the baseline average while a small region in southern Saskatchewan recorded temperatures just slightly below the baseline average.[18]

In February 2025, FERC and NERC and its Regional Entities launched a joint review of the BPS' performance during the January 2025 arctic events, which comprised Winter Storms Blair, Cora, Demi, and Enzo.[19] The week of January 19–25, 2025 was the third coldest winter week (spanning Sunday through Saturday) across the United States since 2000. Between January 21 and 22, 2025, natural gas demand peaked at 150 Bcf/day, electric demand peaked at 683 GW, and unplanned outages peaked at 71,022 MW. Nevertheless, during the January 2025 arctic events, manual load shed was not required. The January 2025 arctic events had lower observed hourly wind chill temperatures in pockets of the Northeast, the Louisiana Gulf, California, and the Southwest compared to Winter Storms Uri, Elliott, Gerri, and Heather. During the January 2025 arctic events, the most extreme storm relative to typical weather was Winter Storm Enzo—a Gulf and Southern storm. On January 20, 2025, a burst of snow, sleet, and freezing rain developed across Texas and Louisiana late in the day. A mixture of sleet and freezing rain fell from Austin to San Antonio and to the southernmost point of Texas. By the early morning hours of January 21, 2025, for the first time in history, a blizzard warning was issued for southwest Louisiana and the southeastern-most point of Texas. Snow fell in Gulf cities in Texas, southern Mississippi, southern Alabama, and western Florida. On January 21, 2025, Baton Rouge recorded 7.6 inches of snowfall, making it the city's snowiest day since recordkeeping began in 1892, while New Orleans saw its snowiest day on record, with a total of 8.0 inches. Temperatures plunged to single digits in Louisiana. Temperatures in some parts of the state fell to levels not seen in more than 125 years.

The review team engaged with 10 electric entities across the Eastern and Texas Interconnections to gather the information necessary to provide a high-level overview of the BPS' performance during the cold weather events. Based on the data and interviews that the team reviewed, electric generators appear to have performed better during the January 2025 arctic events because of additional generator commitments, improved preparedness, increased situational awareness, and the implementation of lessons learned from previous extreme cold weather events and prior report recommendations. The natural gas system also performed better overall, serving record levels of natural gas demand and experiencing only minor production declines and short-duration force majeure events.

On October 1, 2025, NERC submitted to the Federal Energy Regulatory Commission its first *Cold Weather Data Annual Report*. This report includes a review of forced outage data from GADS for the winter 2024–2025 period indicating performance consistent with historical performance as reported in NERC's annual *State of Reliability* report. This is within the normal range of capacity that occurs across the fleet. During the Winter 2024–2025 period, the highest amount of capacity in a forced outage state for all reasons occurred on January 20, 2025, with 68,519 MW across all regions. The outages occurring over January 20, 2025, were analyzed as part of the joint FERC, NERC, and Regional Entity *2025 System Performance Review*. The joint FERC, NERC, and Regional Entity *2025 System Performance Review* found a reduction in peak coincident unplanned generator outages for the four 2025 winter storms reviewed compared to past winter storms; however, this review also noted that it was not an exact comparison due to prior winter storms having different characteristics.

Eastern Interconnection–Canada and Québec Interconnection

No EEAs were needed during the previous winter season. One entity plans to make a slight increase to the demand-response program based on last winter's operations.

[17] Despite Arctic air outbreaks, U.S. had warm, dry winter on average | National Oceanic and Atmospheric Administration
[18] Climate Trends and Variations Bulletin – Winter 2024/2025 - Canada.ca
[19] https://www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional

Eastern Interconnection–United States

Several entities indicated that generators performed better during the January 2025 arctic events than in previous winter storms. For example, TVA stated that generator performance within its footprint was stable, with minimal natural gas delivery issues. Southeastern RC detailed that no major fuel-related outages occurred. FRCC noted that generator performance was strong during this period. The significant characteristics of Winter Storm Enzo in the Southern and Gulf states were freezing precipitation and snow accumulation, especially in regions where those conditions rarely occur. In FRCC, only the northern portion of Florida experienced severe arctic weather including freezing precipitation and snowfall (record-setting, in some cities) that were abnormal for the region even though certain northern cities have faced cold temperatures in the past. In Florida, entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events. ISO-NE, NYISO, and PJM all generally described the January 2025 arctic events as having cold temperatures but overall weather conditions that were similar to a winter without a major storm.

MISO emerged from Winter 2024–2025 without turning to emergency procedures despite the wide-ranging winter storms from January 6 to 9 and again from January 20 to 22. Generators continue to prioritize scheduling planned or maintenance outages to the shoulder seasons of fall and spring to maximize unit availability for the winter season. Also, extreme cold weather outage adders were added to the LOLE model to make sure that winter storm risks are included in planning. In PJM, demand reached a new all-time winter peak on January 22, 2025, of 143,714 MW with sufficient reserves. PJM did call an EEA1 on January 22, 2025, however reserves remained adequate. PJM had less than 3% load forecast error over the peak days of the January cold weather events. Reliability cases were conducted, and units with extended start times were evaluated and started early to ensure units were on-line before extreme cold weather settled in. PJM had a 9.24% forced outage rate on the peak day, a relatively low forced outage rate for the weather experienced. There were also very few gas production problems; however, market issues prevented proper scheduling because of the four-day holiday weekend.

In SERC-Central, entities reported only limited impacts from Winter 2024–2025 coldest weather and made minor adjustments. One entity declared conservative operations ahead of peak conditions but experienced no emergencies. One entity raised its winter Planning Reserve Margin target to 26% following lessons learned from Winter Storm Elliott. Corrective actions were implemented due to isolated equipment issues, including improved heat trace capabilities and adding heat trace equipment to the cold weather critical component list. During the previous winter season, some SERC-Florida Peninsula entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Despite these challenges, entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events.

Texas Interconnection–ERCOT

There were no energy emergencies for the Texas RE-ERCOT region last winter and no conditions that prompted changes in operating procedures. Winter Storm Kingston, which occurred in February 2025, was the only storm where ERCOT utilized firm fuel supply service resources (FFSS), a firm-fuel product that provides additional grid reliability and resiliency during extreme cold weather and compensates generation resources that meet a higher resiliency standard. A maximum FFSS deployment of 470 MW occurred on February 19 between the hours 13:10 and 17:02. Two other storms, Enzo and Cora, impacted ERCOT in January 2025, but these storms did not cause any system reliability issues.

Western Interconnection

Between January 11 and 17, 2024, a prolonged Arctic outbreak impacted British Columbia, Alberta, and the U.S. Pacific Northwest, driving record electricity demand and widespread reliability challenges. Four U.S. Northwest BAs and one Canadian BA declared energy emergencies, underscoring two core vulnerabilities: Inadequate capacity during evening peak hours (4 to 8 p.m.) and Insufficient fuel supply (limited hydro availability) across multiple days.

Although temperatures were comparable to the December 2022 cold snap, WECC-Northwest peak demand rose two percentage points to 6% over then, with BC Hydro and AESO both setting new all-time records. The U.S. Northwest relied heavily on imports—averaging 4,745 MW during peaks and 5,241 MW across all hours, mostly from the Southwest and Rockies. California remained a net importer, providing little relief. Market prices in the Northwest reached or neared caps across most hours, indicating persistent scarcity rather than short-term peaks. Overall, the January 2024 event illustrated capacity alone does not ensure resilience. Sustained energy availability with interregional flexibility (both physical and market-based) will be key to maintaining reliability through the 2025–2026 and future winter seasons.

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
MISO	Jan. 21	18:00	108,888*	96,134 100,395	101,655	-977	18,468	16,761	0	519	17,010
MRO-Manitoba Hydro	Jan. 20	08:00	5.132	4,814 5,060	5,292	-277	142	52	N/A	0	146
MRO-SaskPower	Dec. 18	18:00	3,785	3,802 3,897	3,641	-231	664	368	0	3	0
MRO-SPP	Feb. 20	08:00	47,981	45,926 47,054	40,898	-1,424	4,886	4,783	255	36	9,272
NPCC-Maritimes	Jan. 22	07:00	5,810	5,907 6,498	4,266	-1,174	368	261	3	5	*
NPCC-New England	Jan. 21	18:00	19,607	20,308 21,814	17,686	-1,896	285	329	4	23	624
NPCC-New York	Jan. 22	19:00	23,521	22,998 24,023	18,932	-4,589	654	728	0	0	4,835

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
NPCC-Ontario	Jan. 22	18:00	21,940	20,951	24,250	2,990	3,693	1,914	0	0	*
				22,179							
NPCC-Québec	Jan. 22	08:00	37,178	36,061	39,514	-766	1,463	1,449	0	0	*
				39,545							
PJM	Jan. 22	09:00	144,420	130,712	152,142	7,731	3,704	3,620	3,076	1	8,663
				144,939							
SERC-C	Jan. 22	08:00	47,815	41,397	40,898	-6,921	563	176	214	455	1,538
				47,062							
SERC-E	Jan. 23	08:00	47,130	44,023	41,810	-5,323	0	0	145	2,526	1,830
				47,662							
SERC-FP	Jan. 25	08:00	43,974	45,714	41,702	-557	0	0	362	1,684	2,824
				54,239							
SERC-SE	Jan. 22	08:00	46,490	43,670	48,227	1,741	0	0	592	3,861	2,210
				45,116							

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	Peak Demand Date	Peak Demand Hour	Demand[1] (MW)	WRA Peak Demand Scenarios[2] (MW)	Generation[1] (MWh)	Transfers[1] (MW)	Wind – Actual[1] (MWh)	Wind – Expected[3] (MW)	Solar – Actual[1] (MWh)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
TRE-ERCOT	Feb. 20	08:00	80,560	73,193[5] 90,405[5]	79,960	-191	9,397	15,697	1,586	15	5,742
WECC-AB	Dec. 18	17:00	12,241	12,280 12,635	12,711	-470	3,175	1,867	4	0	*
WECC-BC	Feb 3	18:00	11,359	11,996 12,749	11,415	44	70	279	0	0	839
WECC-CA/MX	Dec. 12	15:00	35,555	35,359 36,823	31,925	-4,669	4,021	569	11,547	0	1,627
WECC-NW	Feb. 12	08:00	54,278	58,001 62,230	48,437	-920	2,607	7,876	1,494	2,198	3,281
WECC-SW	Feb. 13	16:00	22,969	16,177 17,777	25,087	2,117	2,741	1,065	1,599	182	1,496
Highlighting Notes:			Actual peak demand in the highlighted areas met or exceeded extreme scenario levels				Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

2024–2025 Winter Demand and Generation Summary at Peak Demand

Assessment Area	Peak Demand Date	Peak Demand Hour	Demand[1] (MW)	WRA Peak Demand Scenarios[2] (MW)	Generation[1] (MWh)	Transfers[1] (MW)	Wind – Actual[1] (MWh)	Wind – Expected[3] (MW)	Solar – Actual[1] (MWh)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)

Table Notes:

[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from [EIA From 930 data](). For areas in Canada, this data was provided to NERC by system operators and utilities.

[2] See NERC *2024–2025* WRA demand scenarios for each assessment area. Values are the normal winter peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.

[3] Expected values of wind and solar resources from the *2024–2025 WRA*.

[4] Values from NERC Generator Availability Data System for the 2024–2025 winter hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024–2025 winter risk period scenarios in the *2024–2025 WRA*.

[5] Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (5.4 GW for winter 2024-2025) to the demand scenarios found on p. 29 of the 2024-2025 WRA.

*Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

Errata

December 2025

- Corrections made to the VER Table (page 50): Hydro values for WECC NW, Western Interconnection Total, and Total

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 2-60:
Department Press Release on Centralia Order

U.S. DEPARTMENT of ENERGY

Energy Secretary Ensures Washington Coal Plant Remains Open to Ensure Affordable, Reliable and Secure Power Heading into Winter

U.S. Secretary of Energy Chris Wright today issued an emergency order to ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity heading into the cold winter months.

Energy.gov

December 17, 2025

2 min

Emergency order addresses critical grid reliability issues, lowering risk of blackouts and ensuring affordable electricity access

WASHINGTON—U.S. Secretary of Energy Chris Wright today issued an emergency order to ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity heading into the cold winter months. The order directs TransAlta to keep Unit 2 of the Centralia Generating Station in Centralia, Washington available to operate. Unit 2 of the coal plant was scheduled to shut down at the end of 2025. The reliable supply of power from the Centralia coal plant is essential for grid stability in the Northwest. The order prioritizes minimizing the risk and costs of blackouts.

"The last administration's energy subtraction policies had the United States on track to experience significantly more blackouts in the coming years — thankfully, President Trump won't let that happen," said **Energy Secretary Wright**. "The Trump administration will continue taking action to keep America's coal plants running so we can stop the price spikes and ensure we don't lose critical generation sources. Americans deserve access to affordable, reliable, and secure energy to heat their homes all the time, regardless of whether the wind is blowing or the sun is shining."

According to DOE's Resource Adequacy Report, blackouts were on track to potentially increase 100 times by 2030 if the U.S. continued to take reliable power offline as it did during the Biden administration.

The North American Electric Reliability Corporation (NERC) determined in its 2025-2026 Winter Reliability

Assessment that the WECC Northwest region is at elevated risk during periods of extreme weather, such as prolonged, far-reaching cold snaps.

This order is in effect beginning on December 16, 2025, and continuing until March 16, 2026.

Background:

The NERC Winter Reliability Assessment warns that "extreme winter conditions extending over a wide area could result in electricity supply shortfalls." With winter electricity demand continuing to rise, peak demand in the U.S. increased by 2.5% since last winter.

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