BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-101:
TransAlta Annual Information Form for Year Ended Dec. 31, 2024

transalta™



Energizing the Future.

Annual Information Form

for the Year Ended December 31, 2024

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Presentation of Information

The information contained in this Annual Information Form (AIF) is given as of or for the year ended Dec. 31, 2024, unless otherwise noted. All dollar amounts are in Canadian dollars, unless otherwise noted. All references to the "Company" and to "TransAlta", "we", "our" and "us" refer to TransAlta Corporation and its subsidiaries on a consolidated basis. Reference to "TransAlta Corporation" refer to TransAlta Corporation only. Certain capitalized terms defined throughout the body of this AIF and abbreviations and acronyms that may not otherwise be defined are defined in Appendix "B" – Glossary of Terms.

Certain portions of TransAlta's management's discussion and analysis dated Feb. 19, 2025 (MD&A) are incorporated by reference into this AIF as stated below and noted elsewhere in this AIF. The MD&A can be found on SEDAR+ at **www.sedarplus.ca** and EDGAR at **www.sec.gov**.

Forward-Looking Statements

This AIF, including the information incorporated by reference herein, includes "forward-looking information," within the meaning of applicable Canadian securities laws, and "forward-looking statements," within the meaning of applicable U.S. securities laws, including the *Private Securities Litigation Reform Act of 1995* (collectively referred to herein as forward-looking statements).

Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "can", "could", "would", "shall", "believe", "expect", "estimate", "anticipate", "intend", "plan", "forecast", "foresee", "potential", "enable", "continue" or other comparable terminology. These statements are not guarantees of our future performance, events or results and are subject to risks, uncertainties and other important factors that could cause our actual performance, events or results to be materially different from those set out in or implied by the forward-looking statements.

In particular, this AIF (including the information incorporated by reference herein) contains forward-looking statements about the following, among other things:

- The strategic objectives of the Company and that the execution of the Company's strategy will realize value for shareholders;
- Our capital allocation and financing strategy;
- Our sustainability goals and targets, including those in our 2024 Sustainability Report;
- Our 2025 Outlook;
- Our financial and operational performance, including our hedge position;
- Optimizing and diversifying our existing assets;
- The increasingly contracted nature of our fleet;
- Expectations about strategies for growth and expansion, including opportunities for Centralia redevelopment, and data centre opportunities;
- Expected costs and schedules for planned projects;
- Expected regulatory processes and outcomes, including in relation to the Alberta restructured energy market;
- The power generation industry and the supply and demand of electricity;
- The cyclicality of our business;
- Expected outcomes with respect to legal proceedings;
- The expected impact of future tax and accounting changes; and
- Expected industry, market and economic conditions.

The forward-looking statements contained in this AIF (or incorporated herein by reference) are based on many assumptions including, but not limited to, the following:

- No significant changes to applicable laws and regulations;
- No unexpected delays in obtaining required regulatory approvals;
- No material adverse impacts to investment and credit markets;
- No significant changes to power price and hedging assumptions;
- No significant changes to gas commodity price assumptions and transport costs;
- No significant changes to interest rates;
- No significant changes to the demand and growth of renewables generation;
- No significant changes to the integrity and reliability of our facilities;
- No significant changes to the Company's debt and credit ratings;
- No unforeseen changes to economic and market conditions; and
- No significant event occurring outside the ordinary course of business.

These assumptions are based on information currently available to TransAlta, including information obtained from third-party sources. Actual results may differ materially from those predicted.

Factors that may adversely impact what is expressed or implied by forward-looking statements contained in this AIF (or incorporated herein by reference) include, but are not limited to:

- Fluctuations in power prices;
- Changes in supply and demand for electricity;
- Our ability to contract our electricity generation for prices that will provide expected returns;
- Our ability to replace contracts as they expire;
- Risks associated with development projects and acquisitions;
- Any difficulty raising needed capital in the future on reasonable terms or at all;
- Our ability to achieve our targets relating to environmental, social and governance (ESG) performance;
- Long-term commitments on gas transportation capacity that may not be fully utilized over time;
- Changes to the legislative, regulatory and political environments;
- Environmental requirements and changes in, or liabilities under, these requirements;
- Operational risks involving our facilities, including unplanned outages and equipment failure;
- Disruptions in the transmission and distribution of electricity;
- Reductions in production;
- Impairments and/or writedowns of assets;
- Adverse impacts on our information technology systems and our internal control systems, including increased cybersecurity threats;
- Commodity risk management and energy trading risks;
- Reduced labour availability and ability to continue to staff our operations and facilities;
- Disruptions to our supply chains;
- Climate-change related risks;
- Reductions to our generating units' relative efficiency or capacity factors;
- General economic risks, including deterioration of equity and debt markets, increasing interest rates or rising inflation;
- General domestic and international economic and political developments, including potential trade tariffs;
- Industry risk and competition;
- Counterparty credit risk;

- Inadequacy or unavailability of insurance coverage;
- Increases in the Company's income taxes and any risk of reassessments;
- Legal, regulatory and contractual disputes and proceedings involving the Company;
- Reliance on key personnel; and
- Labour relations matters.

The foregoing risk factors, among others, are described in further detail under the heading "Governance and Risk Management" in the MD&A, which section is incorporated by reference herein.

Readers are urged to consider these factors carefully when evaluating the forward-looking statements and are cautioned not to place undue reliance on them. The forward-looking statements included in this AIF are made only as of the date hereof and we do not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise, except as required by applicable laws. The purpose of the financial outlooks contained herein (including as may be incorporated by reference) is to give the reader information about management's current expectations and plans and readers are cautioned that such information may not be appropriate for other purposes.

Non-IFRS Financial Measures

We use a number of financial measures to evaluate our performance and the performance of our business segments, including measures and ratios that do not have any standardized meaning under International Financial Reporting Standards (IFRS), and therefore are unlikely to be comparable to similar measures presented by other companies and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS. In addition, TransAlta cautions the reader that information provided in this AIF regarding the Company's outlook on certain matters, is provided to give context to the nature of some of the Company's future plans and may not be appropriate for other purposes. Refer to the "Additional IFRS Measures and Non-IFRS Financial Measures" and "Key Non-IFRS Financial Ratios" sections of the MD&A, for more information, which sections are incorporated by reference.

Corporate Structure

Name and Incorporation

TransAlta is a corporation organized under the *Canada Business Corporations Act* (CBCA). The Company was formed by a Certificate of Amalgamation issued on Oct. 8, 1992. On Dec. 31, 1992, a Certificate of Amendment was issued in connection with a plan of arrangement under the CBCA involving the Company and TransAlta Utilities Corporation (TransAlta Utilities or TAU). The plan of arrangement, which was approved by shareholders on Nov. 26, 1992, resulted in shareholders of TAU exchanging their common shares for common shares of TransAlta Corporation on a one-for-one basis. Upon completion of the arrangement, TAU became a wholly owned subsidiary of TransAlta Corporation.

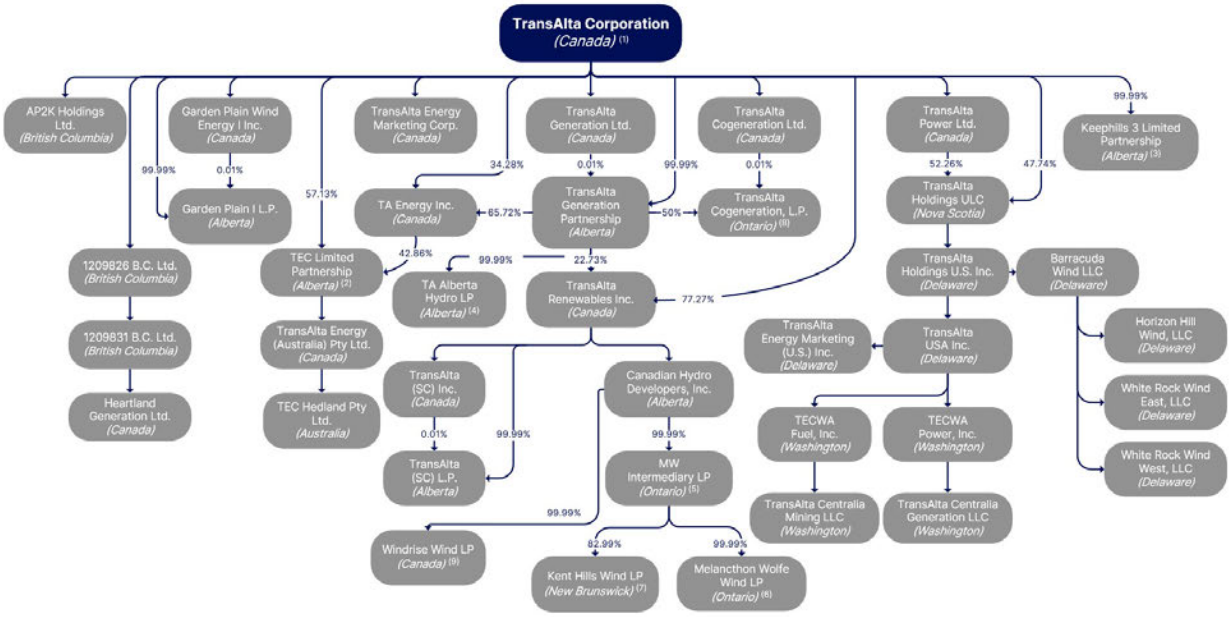
Effective Jan. 1, 2009, we completed a reorganization, whereby the assets and business affairs of TAU and TransAlta Energy Corporation (TransAlta Energy) (with the exception of the wind business) were transferred to TransAlta Generation Partnership, a then new Alberta general partnership, whose partners are the Company and TransAlta Generation Ltd., a wholly owned subsidiary of TransAlta. TransAlta Generation Partnership is managed by TransAlta Corporation pursuant to the terms of a partnership agreement and a management services agreement. Immediately following the transfer of assets by TAU and TransAlta Energy to TransAlta Generation Partnership, TransAlta Corporation amalgamated with TAU, TransAlta Energy and Keephills 3 GP Ltd. pursuant to the provisions of the CBCA. Effective June 1, 2023, TransAlta Corporation amalgamated with its wholly owned subsidiary TransAlta Investment Ltd. On Oct. 5, 2023, TransAlta Corporation acquired all of the outstanding common shares of TransAlta Renewables Inc. (TransAlta Renewables) not already owned, directly or indirectly, by the Company.

We amended our articles at several instances in connection with issuances of preferred shares including on Oct. 1, 2020, when we created the Series I Shares, a new series of redeemable, retractable first preferred shares that were issued to an affiliate of Brookfield Renewable Partners (Brookfield). See the "Capital Structure – Exchangeable Securities" section of this AIF.

Our registered and head office is located at TransAlta Place, Suite 1400, 1100 1 St SE, Calgary, Alberta, Canada, T2G 1B1.

Intercorporate Relationships

As of Dec. 31, 2024, our principal subsidiaries and their respective jurisdictions of formation are set out in the organization chart below. The Company's remaining subsidiaries each account for (i) less than 10 per cent of the Company's consolidated assets as at Dec. 31, 2024 and (ii) less than 10 per cent of the Company's consolidated revenues for the year ended Dec. 31, 2024. The diagram below does not include all of the subsidiaries of TransAlta. The total assets and revenues of excluded subsidiaries in the aggregate did not exceed 20 per cent of the Company's total consolidated assets or total consolidated revenues as at and for the year ended Dec. 31, 2024.



(1) Unless otherwise stated, ownership is 100 per cent.

(2) The remaining 0.01 per cent of TEC Limited Partnership is owned by TransAlta (Ft. McMurray) Ltd, a wholly owned subsidiary of the Company.

(3) The remaining 0.01 per cent of Keephills 3 Limited Partnership is owned by Vision Quest WindElectric Ltd., a wholly owned subsidiary of the Company.

(4) The remaining 0.01 per cent of TA Alberta Hydro LP is owned by TA Alberta Hydro Inc., a wholly owned subsidiary of the Company.

(5) The remaining 0.01 per cent of MW Intermediary LP is owned by MW Intermediary Inc., a wholly owned subsidiary of Canadian Hydro Developers, Inc.

(6) The remaining 0.01 per cent of Melancthon Wolfe Wind LP is owned by Melancthon Wolfe Wind Inc., a wholly owned subsidiary of MW Intermediary LP.

(7) Of the 17.01 per cent of Kent Hills Wind LP, 17.00 per cent is owned by Natural Forces Technologies Inc. and 0.01 percent is owned by Kent Hills Wind Inc.

(8) The remaining 49.99 per cent of TransAlta Cogeneration LP is owned by CPH Cogen Inc.

(9) The remaining 0.01 per cent of Windrise Wind LP is owned by Windrise Wind Energy Inc., a wholly owned subsidiary of Canadian Hydro Developers, Inc.

General Development of the Business

Summarized below are significant developments that have occurred in our business segments during the last three financial years. These events include growth, innovation, acquisitions, recontracting, retirement of assets, dispositions, corporate changes, and other events or conditions that have influenced the general development of the Company's business.

Three-Year History

2024

Acquisition of Heartland Generation from Energy Capital Partners

On Dec. 4, 2024, the Company closed the acquisition of Heartland Generation Ltd. and certain affiliates (collectively, Heartland) for a purchase price of $542 million from an affiliate of Energy Capital Partners (ECP), the parent of Heartland (the Transaction). To meet the requirements of the federal Competition Bureau, the Company entered into a consent agreement with the Commissioner of Competition pursuant to which TransAlta agreed to divest Heartland's Poplar Hill and Rainbow Lake assets (the Planned Divestitures) following closing of the Transaction. In consideration of the Planned Divestitures, TransAlta and ECP agreed to a reduction of $80 million from the original purchase price for the Transaction. ECP will be entitled to receive the proceeds from the sale of Poplar Hill and Rainbow Lake, net of certain adjustments following completion of the Planned Divestitures. TransAlta also received a further $95 million at closing of the Transaction to reflect the economic benefit of the Heartland business arising from Oct. 31, 2023 to the closing date of the Transaction, pursuant to the terms of the share purchase agreement. The net cash payment for the Transaction, before working capital adjustments, totalled $215 million, and was funded through a combination of cash on hand and draws on TransAlta's credit facilities.

Excluding the Planned Divestitures, the Transaction adds 1,747 MW (net interest) of complementary capacity from nine facilities, including contracted cogeneration and peaking generation, legacy gas-fired thermal generation, and transmission capacity, all of which will be critical to support reliability in the Alberta electricity market.

Mothballing of Sundance Unit 6

On Nov. 4, 2024, the Company provided notice to the Alberta Electric System Operator (AESO) that Sundance Unit 6 will be mothballed on April 1, 2025, for a period of up to two years depending on market conditions. TransAlta maintains the flexibility to return the mothballed unit to service when market fundamentals or opportunities to contract are secured. The unit remains available and fully operational for the first quarter of 2025.

Horizon Hill Wind Facility

On May 21, 2024, the 202 MW Horizon Hill wind facility achieved commercial operation. The facility is located in Logan County, Oklahoma and is fully contracted to Meta Platforms Inc. for the offtake of 100 per cent of the generation.

White Rock Wind Facility

On Jan. 1, 2024, the 100 MW White Rock West wind facility achieved commercial operation. On April 22, 2024, the 202 MW White Rock East wind facility also completed commissioning. The facilities are located in Caddo County, Oklahoma and are contracted under two long-term power purchase agreements (PPAs) with Amazon Energy LLC for the offtake of 100 per cent of the generation.

Production Tax Credit (PTC) Sale Agreements

On Feb. 22, 2024, the Company entered into 10-year transfer agreements with an AA- rated customer for the sale of approximately 80 per cent of the expected PTCs to be generated from the White Rock and the Horizon Hill wind facilities.

On June 21, 2024, the Company entered into an additional 10-year transfer agreement with an A+ rated customer for the sale of the remaining 20 per cent of the expected PTCs.

Mount Keith West Network Upgrade Project.

Construction of the Mount Keith West Network upgrade project commenced in the fourth quarter of 2024 under the PPA with BHP Nickel West. The works comprise upgrades to the Mount Keith 132kV network via an extension of existing Gas Insulated Switchgear, new 132kV transformers and new 11kV switchrooms that will replace legacy 11kV switchgear located at TransAlta's diesel power station.

Mount Keith 132kV Transmission Expansion

The Mount Keith 132kV expansion project was completed during the first quarter of 2024. The expansion was developed under the existing PPA with BHP Nickel West (BHP), which extends until Dec. 31, 2038. The expansion will facilitate the connection of additional generating capacity to the transmission network which supports BHP's operations.

Normal Course Issuer Bid

During the year ended Dec. 31, 2024, the Company purchased and cancelled a total of 13,467,400 common shares, pursuant to its Normal Course Issuer Bid program at an average price of $10.59 per common share, for a total cost of $143 million, including taxes.

2023

Northern Goldfields Solar Achieves Commercial Operation

On Nov. 22, 2023, the 48 MW Northern Goldfields solar and battery storage facilities achieved commercial operation. The facilities consist of the 27 MW Mount Keith solar facility, the 11 MW Leinster solar facility, the 10 MW Leinster battery energy storage system and interconnecting transmission infrastructure, all of which are now integrated into TransAlta's existing 145 MW Southern Cross Energy North remote network in Western Australia. The facilities are fully contracted to BHP under a PPA expiring in 2038.

Kent Hills Wind Facilities

Our Kent Hills wind facilities were partially returned to service in the fourth quarter of 2023, with all turbines commissioned and the remediation project completed in the first quarter of 2024. On June 2, 2022, we announced the rehabilitation plan for the Kent Hills 1 and 2 wind facilities. In addition to the announcement, TransAlta amended and extended PPAs with New Brunswick Power Corporation (NB Power) in respect of each of the Kent Hills 1, 2 and 3 wind facilities, providing for an additional 10-year contract term to December 2045 and an effective 10 per cent reduction to the original contract prices from January 2023 through December 2033. In addition, both parties have agreed to work in good faith to evaluate the installation of a battery energy storage system at Kent Hills and to consider a potential repowering of Kent Hills at the end of life in 2045.

Garden Plain Wind Facility Reaches Commercial Operations

In August 2023, the Garden Plain wind facility was commissioned adding 130 MW to our gross installed capacity. The facility is fully contracted with Pembina Pipeline Corporation (Pembina) and PepsiCo Canada (PepsiCo), with a weighted average contract life of approximately 17 years. The facility consists of 26 Siemens-Gamesa turbines.

Acquisition of TransAlta Renewables Inc.

On Oct. 5, 2023, the Company completed the acquisition of TransAlta Renewables for $1.3 billion, consisting of $800 million of cash and approximately 46 million common shares of the Company. TransAlta's acquisition of TransAlta Renewables' common shares resulted in TransAlta Renewables becoming a wholly owned subsidiary of the Company. Prior thereto, TransAlta and its affiliates collectively owned 60.1 per cent of TransAlta Renewables.

Pingston Successfully Recontracted

During 2023, the Company successfully recontracted the Pingston facility for a period of 20 years. Pingston is a 45 MW run-of-river hydroelectric facility located on Pingston Creek, British Columbia.

2022

Public Offering of US Senior Green Bonds and Release of Inaugural Green Bond Framework

On Nov. 17, 2022, the Company issued US$400 million Senior Notes, which have a coupon rate of 7.750 per cent per annum and mature on Nov. 15, 2029.

The Company allocated an amount equal to the net proceeds from this offering to finance or refinance new and/or existing eligible green projects in accordance with its Green Bond Framework (the Framework). The Framework received a second-party opinion from Sustainalytics, which verified that it aligned with the Green Bond Principles from the International Capital Market Association.

Executed Industrial Contract Extensions at Sarnia Cogeneration

During the second and fourth quarters of 2022, the Company executed contracts for the supply of electricity and steam from the Sarnia cogeneration facility with three of its legacy industrial customers, and three new customers, who had previously been resold utilities as part of a legacy customer's contract. Following the contracting efforts in 2021 and 2022, the Sarnia cogeneration facility has been fully recontracted without interruption to the customers' delivery terms. The contracts extend to April 30, 2031, for four customers, and to Dec. 31, 2032 for the other three customers.

Executed Contract Renewals with the IESO at Sarnia Cogeneration and Melancthon 1 Wind Facilities

On Aug. 23, 2022, TransAlta was awarded capacity contracts for the Sarnia cogeneration facility and the Melancthon 1 wind facility from the Ontario Independent Electricity System Operator (IESO) as part of the IESO's Medium-Term Capacity Procurement Request for Proposals. The capacity contracts run from May 1, 2026, to April 30, 2031.

Business of TransAlta

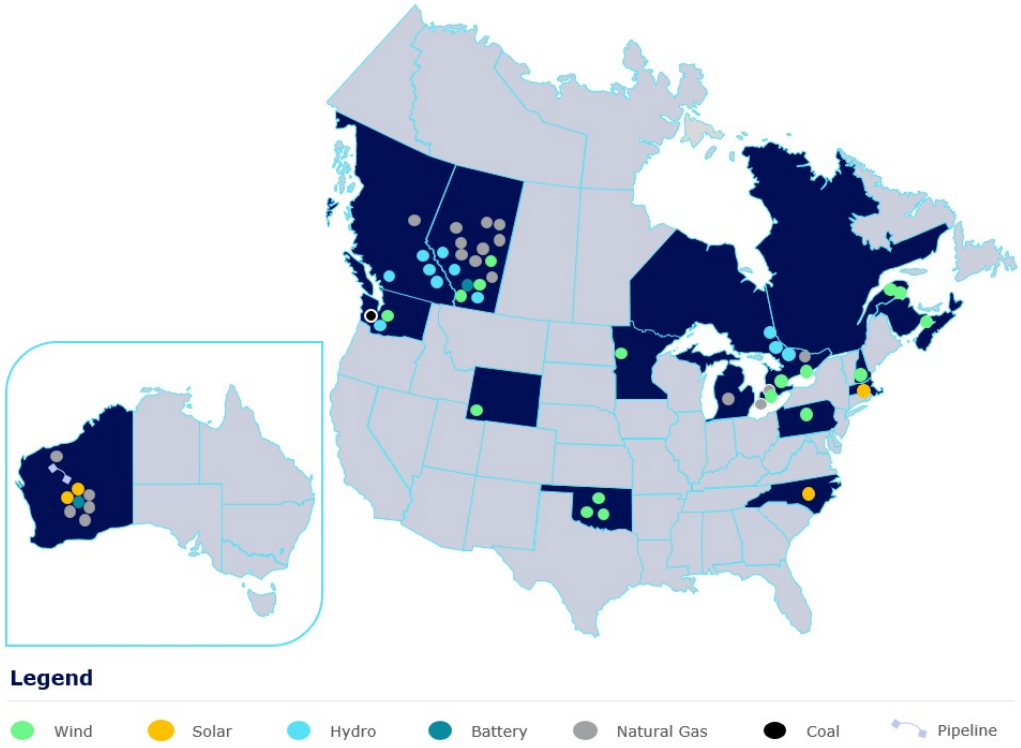
Our Hydro, Wind and Solar, Gas and Energy Transition segments are responsible for operating and maintaining our electrical generation facilities in Canada, the United States and Western Australia. Our Energy Marketing segment is responsible for marketing and scheduling our merchant asset fleet in North America (excluding Alberta) along with the procurement of natural gas, transport and storage for our gas fleet, providing knowledge to support our growth team, and generating a stand-alone gross margin separate from our asset business through a leading North American energy marketing platform and trading.

In Alberta, the Company manages merchant exposure by executing hedging strategies that include a significant base of commercial and industrial customers, supplemented with financial hedges. A significant portion of our thermal generation capacity in Alberta is hedged to provide greater cash flow certainty while also capturing higher returns for our shareholders through the optimization of our merchant generation portfolio.

These segments are all supported by a Corporate segment.

TransAlta's Map of Operations

The following map outlines the Company's operations as of Dec. 31, 2024:



The following sections of this AIF provide detailed information on facilities by geographic location and fuel type.

Hydro Segment

The Hydro segment holds a net capacity interest of 922 MW of generating capacity. The facilities are located in Alberta, British Columbia, and Ontario.

As well as contracting for power, we enter into long and short-term contracts to sell the environmental attributes from our merchant hydro facilities. These activities help to ensure earnings stability from these assets. Generally, for facilities under long-term contracts, the benefit of the environmental attributes generated is provided to the contract holder.

The following table summarizes our hydroelectric facilities as at Dec. 31, 2024:

Facility Name	Province	Nameplate Capacity (MW)[1]	Consolidated Interest	Gross Installed Capacity (MW)[1]	Ownership	Net Capacity Ownership Interest (MW)[1]	Commercial Operation Date[2]	Revenue Source[3]	Contract Expiry Date[4]
Alberta - Bow River System									
Barrier[5][6]	AB	13	100 %	13	100 %	13	1947	Merchant	-
Bearspaw[5][6]	AB	17	100 %	17	100 %	17	1954	Merchant	-
Cascade[5][6]	AB	36	100 %	36	100 %	36	1942, 1957	Merchant	-
Ghost[5][6]	AB	54	100 %	54	100 %	54	1929, 1954	Merchant	-
Horseshoe[5][6]	AB	14	100 %	14	100 %	14	1911	Merchant	-
Interlakes[5][6]	AB	5	100 %	5	100 %	5	1955	Merchant	-
Kananaskis[5][6]	AB	19	100 %	19	100 %	19	1913, 1951	Merchant	-
Pocaterra[6]	AB	15	100 %	15	100 %	15	1955	Merchant	-
Rundle[5][6]	AB	50	100 %	50	100 %	50	1951, 1960	Merchant	-
Spray[5][6]	AB	112	100 %	112	100 %	112	1951, 1960	Merchant	-
Three Sisters[5]	AB	3	100 %	3	100 %	3	1951	Merchant	-
Alberta - Oldman River System									
Belly River[6]	AB	3	100 %	3	100 %	3	1991	Merchant	-
St. Mary[6]	AB	2	100 %	2	100 %	2	1992	Merchant	-
Taylor[6]	AB	13	100 %	13	100 %	13	2000	Merchant	-
Waterton[6]	AB	3	100 %	3	100 %	3	1992	Merchant	-
Alberta - North Saskatchewan River System[6]									
Bighorn[5][6]	AB	120	100 %	120	100 %	120	1972	Merchant	-
Brazeau[5][6]	AB	355	100 %	355	100 %	355	1965, 1967	Merchant	-
BC Hydro									
Akolkolex[6]	BC	10	100 %	10	100 %	10	1995	LTC	2046
Bone Creek[6]	BC	19	100 %	19	100 %	19	2011	LTC	2031
Pingston[6]	BC	45	50 %	22.5	100 %	23	2003, 2004	LTC	2043
Upper Mamquam[6]	BC	25	100 %	25	100 %	25	2005	LTC	2045
Ontario Hydro									
Misema	ON	3	100 %	3	100 %	3	2003	LTC	2027
Moose Rapids[6]	ON	1	100 %	1	100 %	1	1997	LTC	2030
Ragged Chute	ON	7	100 %	7	100 %	7	1991	LTC	2029
Total Hydroelectric Capacity		**944**		**922**		**922**			

(1) MW are rounded to the nearest whole number. The gross installed capacity reflects the basis of conso idation of underlying assets owned, whereas net capacity ownership interest deducts capacity attributable to the non-control ing interest in these assets and is calculated after the consolidation of underlying assets.

(2) A second date in this column refers to a second unit that was subsequently operational.

(3) The large majority of the Company's contracted operating faci ities benefit from inflation adjustment provisions that apply to all or a portion of our revenues under such contracts.

(4) Where no contract expiry date is indicated, the facility operates as merchant.

(5) These faci ities form part of the hydro assets that are subject to an Investment Agreement. See the "Capital Structure – Investment Agreement" section of this AIF for further details.

(6) These facilities are EcoLogo® certified. EcoLogo certification is granted to products with an environmental performance that meets or exceeds all government, industrial safety and performance standards.

Bow River System

Barrier

Barrier is a hydroelectric facility with installed capacity of 13 MW located on the Kananaskis River near Seebe, Alberta. Commercial operations began in 1947. Generation from the facility is currently sold in the Alberta electricity market and creates Emission Performance Credits (EPCs) under the Alberta Technology Innovation and Emissions Reduction (TIER) system.

Bearspaw

Bearspaw is a hydroelectric facility with installed capacity of 17 MW located on the Bow River in Calgary, Alberta. Commercial operations began in 1954. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

Cascade

Cascade is a hydroelectric facility with installed capacity of 36 MW located on the Cascade River in Banff National Park, Alberta. This facility was purchased from the Government of Canada in 1941. The following year, we built a new dam and power plant to replace the original, and then, in 1957, added a second generating unit. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

Ghost

Ghost is a hydroelectric facility with installed capacity of 54 MW located on the Bow River near Cochrane, Alberta. Commercial operations began in 1929. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

Horseshoe

Horseshoe is a run-of-river hydroelectric facility with installed capacity of 14 MW located on the Bow River near Seebe, Alberta. Commercial operations began in 1911. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

Interlakes

Interlakes is a hydroelectric facility with installed capacity of 5 MW located at Kananaskis Lakes, Alberta. Commercial operations began in 1955. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

Kananaskis

Kananaskis is a run-of-river hydroelectric facility with installed capacity of 19 MW located on the Bow River in Seebe, Alberta. Commercial operations began in 1913. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

Pocaterra

Pocaterra is a hydroelectric facility with installed capacity of 15 MW located at Kananaskis Lakes, Alberta. Commercial operations began in 1955. Generation from the facility is sold in the Alberta electricity market and creates EPCs under the TIER system.

Rundle

Rundle is a hydroelectric facility with installed capacity of 50 MW located in Canmore, Alberta, on the Spray system. Commercial operations began in 1951. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

Spray

Spray is a hydroelectric facility with installed capacity of 112 MW located in Canmore, Alberta, on the Spray system. Commercial operations began in 1951. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

Three Sisters

Three Sisters is a hydroelectric facility with installed capacity of 3 MW located at the base of the Three Sisters Dam near Canmore, Alberta, on the Spray system. Commercial operations began in 1951. Generation from the facility is currently sold in the Alberta electricity market.

Oldman River System

Belly River

Belly River is a run-of-river hydroelectric facility with installed capacity of 3 MW located on the Waterton-St. Mary Headworks Irrigation Canal System, east of the Waterton Reservoir, approximately 75 kilometres southwest of Lethbridge in southern Alberta. Due to its location along the irrigation canal, Belly River operates from April to October when water is diverted through the canal as part of the St. Mary Irrigation District Water Management Plan. Commercial operations began in March 1991. Generation from the facility is currently sold in the Alberta electricity market.

St. Mary

St. Mary is a run-of-river hydroelectric facility with installed capacity of 2 MW located at the base of the dam impounding the St. Mary Reservoir, near Magrath, in southern Alberta. Commercial operations began in 1992. Generation from the facility is currently sold in the Alberta electricity market.

Taylor

Taylor is a run-of-river hydroelectric facility with installed capacity of 13 MW and is located adjacent to the Taylor Coulee Chute on the Waterton-St. Mary Headworks Irrigation Canal System, which is owned by the Government of Alberta. Commercial operations began in 2000. Generation from the facility is currently sold in the Alberta electricity market.

Waterton

Waterton is a run-of-river hydroelectric facility with installed capacity of 3 MW located at the base of the Waterton Dam on the Waterton Reservoir, near Hill Spring, southwest of Lethbridge, Alberta. Commercial operations began in 1992. Generation from the facility is currently sold in the Alberta electricity market.

North Saskatchewan River System

Bighorn

Bighorn is a hydroelectric facility with installed capacity of 120 MW located near Nordegg, Alberta. Commercial operations began in 1972. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

Brazeau

Brazeau is a hydroelectric facility with installed capacity of 355 MW located near Drayton Valley, Alberta. Commercial operations began in 1967. Generation from the facility is currently sold in the Alberta electricity market and creates EPCs under the TIER system.

BC Hydro Facilities

Akolkolex

Akolkolex is a run-of-river hydroelectric facility with installed capacity of 10 MW and is located on the Akolkolex River, south of Revelstoke, British Columbia. Commercial operations began in 1995. The output from the facility is sold to British Columbia Hydro and Power Authority (BC Hydro) under a PPA that terminates in 2046.

Bone Creek

Bone Creek is a run-of-river hydroelectric facility with installed capacity of 19 MW and is located on Bone Creek, 90 kilometres south of Valemount, British Columbia. Commercial operations began in 2011. The output from the facility is sold to BC Hydro under a PPA that terminates in 2031.

Pingston

Pingston is a run-of-river hydroelectric facility with installed capacity of 45 MW and is located on Pingston Creek, southwest of Revelstoke, British Columbia, and downriver of the Akolkolex facility. Pingston is equally owned with Evolugen Trading and Marketing LP, a subsidiary of Brookfield. Commercial operations began in 2003. The output from the facility is sold to BC Hydro under a recontracted 20-year PPA that expires on May 8, 2043.

Upper Mamquam

Upper Mamquam is a run-of-river hydroelectric facility with installed capacity of 25 MW located on the Mamquam River, east of Squamish, British Columbia, and north of Vancouver. Commercial operations began in 2005. The output from the facility is sold to BC Hydro under a PPA that terminates in 2045.

Ontario Hydro Facilities

Misema

Misema is a run-of-river hydroelectric facility with installed capacity of 3 MW located on the Misema River, close to Englehart, in northern Ontario. Commercial operations began in 2003. Generation from this facility is sold to the IESO under a contract that terminates on May 3, 2027.

Moose Rapids

Moose Rapids is a run-of-river hydroelectric facility with installed capacity of 1 MW located on the Wanapitei River, near Sudbury, in northern Ontario. Commercial operations began in 1997. Generation from this facility is sold to the IESO under a contract that terminates on Dec. 31, 2030.

Ragged Chute

Ragged Chute is a run-of-river hydroelectric facility with installed capacity of 7 MW located on the Montréal River, south of Temiskaming Shores, in northern Ontario. The Company leases this facility from Ontario Power Generation Inc. (OPG). The facility has been operating since 1991. Generation from this facility is sold to the IESO under a contract that terminates on June 30, 2029. Upon termination, the asset will transfer to OPG together with a payment of $6.6 million to the Company.

Wind and Solar Segment

As at Dec. 31, 2024, the Wind and Solar segment held interests in approximately 2,559 MW of net wind and solar generating capacity. This capacity consists of 12 wind facilities in Western Canada, four in Ontario, two in Québec, three in New Brunswick and eight in the United States, more specifically in Washington, Wyoming, Minnesota, Oklahoma, Pennsylvania and New Hampshire. The Company also holds a 10 MW utility-scale battery energy storage system in Alberta, 143 MW of solar facilities in Massachusetts and North Carolina, and a 38 MW solar facility and a 10 MW battery energy storage system in Western Australia.

In addition to contracting for the sale of the power generation, we also enter into long- and short-term contracts to sell the environmental and tax attributes from the merchant wind and solar facilities. These activities help to ensure earnings consistency from these assets. Generally, for facilities under a long-term PPA, the purchaser also benefits from any environmental attributes associated with the facility.

The following table summarizes our Wind and Solar generation facilities as at Dec. 31, 2024:

Facility Name	Province / State	Nameplate Capacity (MW)[1]	Consolidated Interest	Gross Installed Capacity (MW)[1]	Ownership	Net Capacity Ownership Interest (MW)[1]	Commercial Operation Date[2]	Revenue Source[3]	Contract Expiry Date[4]
Alberta Wind									
Ardenville[5]	AB	69	100 %	69	100 %	69	2010	Merchan	-
Blue Trail and Macleod Fla s[5]	AB	69	100 %	69	100 %	69	2009 and 2004	Merchan	-
Cas le River[5][6]	AB	44	100 %	44	100 %	44	1997-2001	Merchan	-
Cowley Nor h[5]	AB	20	100 %	20	100 %	20	2001	Merchan	-
Garden Plain	AB	130	100 %	130	100 %	130	2023	TC	2035-2041
McBride ake[5]	AB	75	50 %	38	100 %	38	2004	Merchan	
Oldman[5]	AB	4	100 %	4	100 %	4	2007	Merchan	-
Sinno [5]	AB	5	100 %	5	100 %	5	2001	Merchan	-
Soderglen[5]	AB	71	50 %	36	100 %	36	2006	Merchan	-
Summerview 1[5]	AB	68	100 %	68	100 %	68	2004	Merchan	-
Summerview 2 [5]	AB	66	100 %	66	100 %	66	2010	Merchan	-
Windrise	AB	206	100 %	206	100 %	206	2021	TC	2041
Alberta Battery Energy Storage									
WindCharger	AB	10	100 %	10	100 %	10	2020	Merchan	-
Eastern Canada Wind									
Ken Breeze	ON	20	100 %	20	100 %	20	2011	TC	2031
Ken Hills 1	NB	96	100 %	96	83 %	80	2008	TC	2045
Ken Hills 2	NB	54	100 %	54	83 %	45	2010	TC	2045
Ken Hills 3	NB	17	100 %	17	83 %	14	2018	TC	2045
e Nordais[5][7]	QC	98	100 %	98	100 %	98	1999	TC	2033
Melanc hon 1	ON	68	100 %	68	100 %	68	2006	TC	2031
Melanc hon 2	ON	132	100 %	132	100 %	132	2008	TC	2028
New Richmond[5]	QC	68	100 %	68	100 %	68	2013	TC	2033
Wol e sland	ON	198	100 %	198	100 %	198	2009	TC	2029
US Wind									
An rim	NH	29	100 %	29	100 %	29	2019	TC	2039
Big evel	PA	90	100 %	90	100 %	90	2019	TC	2034
Horizon Hill	OK	202	100 %	202	100 %	202	2024	TC	-
akeswind	MN	50	100 %	50	100 %	50	2014	TC	2034
Skookumchuck Wind	WA	137	49 %	67	100 %	67	2020	TC	2040
Whi e Rock Eas	OK	202	100 %	202	100 %	202	2024	TC	-
Whi e Rock Wes	OK	100	100 %	100	100 %	100	2024	TC	-
Wyoming Wind	WY	140	100 %	140	100 %	140	2003	TC	2028
US Solar									
Mass Solar[7]	MA	21	100 %	21	100 %	21	2012-2015	TC	2032-2045
Nor h Carolina Solar[7]	NC	122	100 %	122	100 %	122	2019-2021	TC	2033
Australian Solar									
Nor hern Gold ields[7]	WA	38	100 %	38	100 %	38	2023	TC	2038
Australia Battery Energy Storage									
Nor hern Gold ields Ba ery	WA	10	100 %	10	100 %	10	2023	TC	2038
Total Wind and Solar Capacity		**2,729**		**2,587**		**2,559**			

(1) MW are rounded to the nearest whole number. The gross installed capacity reflects the basis of conso idation of the underlying assets owned, whereas net capacity ownership interest deducts capacity attributable to non-controlling interest in these assets and is calculated after conso idation of the underlying assets.

(2) A second date in this column refers to a second facility that was subsequently operational.

(3) The large majority of the Company's contracted operating facilities benefit from inflation adjustment provisions that apply to all or a portion of our revenues under such contracts.

(4) Where no contract expiry date is indicated, the facility operates as merchant or certain contract terms are confidential and have note been disclosed.

(5) These facilities are EcoLogo® certified. EcoLogo certification is granted to products with an environmental performance that meets or exceeds all government, industrial safety and performance standards.

(6) Includes six additional turbines at other locations.

(7) Includes multiple facilities.

Alberta Wind Facilities

Ardenville

Ardenville is a 69 MW wind facility located approximately 14 kilometres south of Fort Macleod. The facility began commercial operations in November 2010. It satisfies the eligibility criteria for an opted-in facility under Section 4 of the TIER regulation and is voluntarily choosing to participate in the regulation for the purposes of being able to generate emission performance credits (opt-in facility). An opt-in facility is not considered a large emitter of greenhouse gases (GHG) and as such we elected to participate in TIER. Generation from the facility is currently sold in the Alberta electricity market.

Blue Trail and Macleod Flats

Blue Trail is a 66 MW wind facility located in southern Alberta. The facility began commercial operations in November 2009. The Blue Trail wind facility created carbon offset credits under TIER until Sept. 16, 2022, at which time the facility became an opt-in facility under TIER.

Macleod Flats is a 3 MW wind facility located near Fort Macleod. It was commissioned in 2004 and was acquired by TransAlta in 2009. This facility generates Renewable Energy Certificate (REC) credits. Generation from the facilities is currently sold in the Alberta electricity market.

Castle River

Castle River is a 39.5 MW wind facility located southwest of Pincher Creek. This facility also includes an additional six turbines, totalling 4 MW that are located individually in the Cardston County and Hill Spring areas of southwestern Alberta. The facility began commercial operations in stages from November 1997 through to July 2001. This facility generates EPCs under the TIER system. Generation from the facility is currently sold in the Alberta electricity market.

Cowley North

Cowley North is a 19.5 MW wind facility located near the towns of Cowley and Pincher Creek, in southern Alberta. The facility began commercial operations in the fall of 2001. The Cowley North facility creates EPCs under the TIER system. Generation from the facility is currently sold in the Alberta electricity market.

Garden Plain

Garden Plain is a 130 MW wind facility located approximately 30 kilometres north of Hanna. This facility began commercial operations in August 2023. The facility is fully contracted with 100 MW being sold under a PPA with Pembina that terminates in 2041 and the remaining 30 MW of generation being contracted to PepsiCo under a PPA and terminates in 2035.

McBride Lake

McBride Lake is a 75.2 MW wind facility located south of Fort Macleod. The McBride Lake facility is co-owned with ENMAX Generation Portfolio Inc. The facility began commercial operations on April 30, 2004. A 20-year PPA with ENMAX Energy Corporation terminated on April 30, 2024 and generation from the facility is currently sold in the Alberta electricity market.

Oldman

Oldman is a 3.6 MW wind facility located east of the Oldman River Dam, near Pincher Creek in southern Alberta. The facility has been in operation since March 2007. In 2021, TransAlta acquired 100 per cent of the facility from a subsidiary of Boralex. This facility sells energy into the Alberta electricity market.

Sinnott

Sinnott is a 5 MW wind facility located directly east of the Cowley North wind facility and north of Pincher Creek. The facility began commercial operations in the fall of 2001. The facility sells energy into the Alberta electricity market and generates EPCs under the TIER system.

Soderglen

Soderglen is a 71 MW wind facility located southwest of Fort Macleod. The facility is co-owned with CNOOC Petroleum North America ULC. The facility began commercial operations in September 2006. The Soderglen wind facility creates EPCs under the TIER system, of which TransAlta receives 25 per cent. The Company is entitled to 50 per cent of the generation that is sold into the Alberta electricity market.

Summerview 1

Summerview 1 is a 68 MW wind facility located approximately 15 kilometres northeast of Pincher Creek. The facility began commercial operations in September 2004. The facility sells energy into the Alberta electricity market and generates EPCs under the TIER system.

Summerview 2

Summerview 2 is a 66 MW wind facility located approximately 15 kilometres northeast of Pincher Creek. The facility began commercial operations in February 2010. The facility sells energy into the Alberta electricity market and generated carbon offset credits under TIER until November 2022, after which it became an opt-in facility under TIER.

Windrise

Windrise is a 206 MW wind facility located in the county of Willow Creek. The facility began commercial operations in November 2021. Generation from the facility is sold to the AESO under a 20-year PPA that expires in 2041.

Alberta Battery Energy Storage

WindCharger

WindCharger is Alberta's first utility-scale battery storage facility. The facility consists of a lithium-ion battery using Tesla Megapack technology that has a nameplate capacity of 10 MW and a total storage capacity of 20 MWh. WindCharger is located in southern Alberta in the Municipal District of Pincher Creek, next to the Summerview wind facility substation. The storage project achieved commercial operations on Oct. 15, 2020. WindCharger stores energy produced by the nearby Summerview 2 wind facility and discharges this energy for ancillary services. The facility is an opt-in facility under TIER.

Eastern Canada Wind Facilities

Kent Breeze

Kent Breeze is a 20 MW wind facility located in Thamesville, Ontario. The facility began commercial operations in 2011. Generation from this facility is sold to the IESO under a 20-year PPA that expires in 2031.

Kent Hills 1

Kent Hills 1 is a 96 MW wind facility located near Moncton, New Brunswick. The facility began commercial operations in December 2008. The Company owns 83 per cent of the facility and Natural Forces Technologies Inc., a wind developer based in Atlantic Canada that co-developed the project with TransAlta, owns 17 per cent. Generation from this facility is sold under a PPA with NB Power that expires in 2045.

Kent Hills 2

Kent Hills 2 is a 54 MW wind facility located near Moncton, New Brunswick. The facility began commercial operations in November 2010. The Company owns 83 per cent of the facility and Natural Forces Technologies Inc., a wind developer based in Atlantic Canada that co-developed the project with TransAlta, owns 17 per cent. On June 2, 2022, the Company announced the extension of the previous 2035 PPA term for an additional 10-year period through to December 2045.

Kent Hills 3

Kent Hills 3 is a 17.25 MW wind facility located near Moncton, New Brunswick. The facility began commercial operations in November 2018. The Company owns 83 per cent of the facility and Natural Forces Technologies Inc., a wind developer based in Atlantic Canada that co-developed the project with TransAlta, owns 17 per cent. On June 2, 2022, we announced the extension of the previous 2035 PPA term for an additional 10-year period through to December 2045.

Le Nordais

Le Nordais is a 97.5 MW wind facility located on the Gaspé Peninsula of Québec. The facility has two sites, Cap-Chat with 74 turbines and Matane with 56 turbines. The facility began commercial operations in 1999. Generation from this facility is sold to Hydro-Québec pursuant to an energy supply agreement that terminates in 2033, and the facility generates RECs.

Melancthon 1

Melancthon 1 is a 67.5 MW wind facility located in Melancthon Township near Shelburne, Ontario. The facility began commercial operations in March 2006. Generation from this facility is sold to the IESO pursuant to a PPA that expires in 2026; a new Medium-Term 1 (MT1) capacity contract with the IESO will begin on May 1, 2026, and terminate on April 30, 2031. The Company submitted a binding offer in January 2025 to participate in the 5-year Medium-Term 2 Energy Contract (MT2(e)), which will be awarded by April 1, 2025. If successful, this energy contract will replace the MT1 and be effective May 1, 2026 to April 30, 2031.

Melancthon 2

Melancthon 2 is a 132 MW wind facility located adjacent to Melancthon 1, in the Melancthon and Amaranth townships, Ontario. The facility began commercial operations in November 2008. Generation from this facility is sold to the IESO pursuant to a PPA that terminates in 2028. The Company submitted a binding offer in January 2025 to participate in the 5-year MT2(e), which will be awarded by April 1, 2025. If successful, the current PPA will extend to April 30, 2029 and the MT2(e) will be effective May 1, 2029 to April 30, 2034.

New Richmond

New Richmond is a 68 MW wind facility located in New Richmond, Québec. The facility began commercial operations in March 2013. Generation from this facility is sold under a 20-year electricity supply agreement with Hydro-Québec Distribution that terminates in 2033.

Wolfe Island

Wolfe Island is a 197.8 MW wind facility located on Wolfe Island, near Kingston, Ontario. The facility began commercial operations in June 2009. Generation from this facility is sold to the IESO pursuant to a PPA that terminates in 2029. The Company submitted a binding offer in January 2025 to participate in the 5-year MT2(e), which will be awarded by April 1, 2025. If successful, the current PPA will terminate early and the MT2(e) will be effective May 1, 2029 to April 30, 2034.

US Wind and Solar Facilities

Antrim

Antrim is a 28.8 MW wind facility located in Antrim, New Hampshire. The wind facility was commissioned in December 2019. The wind facility is fully operational and contracted under two long-term PPAs until 2039 with Partners Healthcare and New Hampshire Electric. Ninety-nine per cent of production tax credits are allocated to tax equity partners and the remainder is allocated to TransAlta.

Big Level

Big Level is a 90 MW wind facility located in Potter County, Pennsylvania. The wind facility was commissioned in December 2019. Generation from the facility is sold under a PPA with Microsoft that terminates in 2034. Ninety-nine per cent of production tax credits are allocated to tax equity partners and the remainder is allocated to TransAlta.

Horizon Hill

Horizon Hill is a 202 MW wind facility located in Logan County, Oklahoma. 100 per cent of the generation offtake from the project is sold to Meta, under a long-term PPA. Under the PPA, Meta receives both renewable electricity and environmental attributes. The Horizon Hill facilities achieved commercial operation on May 21, 2024. The company has entered into two 10-year transfer agreements with A+ and AA- rated customers for the sale of 100 per cent of the expected production tax credits to be generated from the Horizon Hill, White Rock East, and White Rock West facilities. See the "General Development of the Business – Three-Year History" section of this AIF for further details.

Lakeswind

Lakeswind is a 50 MW wind facility located near Rollag, Minnesota, and is fully operational and contracted under a long-term PPA until 2034 with several high-quality counterparties. Ninety-nine per cent of production tax credits are allocated to tax equity partners and the remainder is allocated to TransAlta.

Mass Solar

Mass Solar is a 21 MW solar portfolio consisting of multiple sites located in Massachusetts, and is contracted under long-term PPAs expiring between 2032 and 2045 with several high-quality counterparties.

North Carolina Solar

North Carolina Solar is a 122 MW solar portfolio consisting of 20 sites located in North Carolina. The facilities were commissioned between November 2019 and May 2021. The facilities are secured by long-term PPAs with two subsidiaries of Duke Energy and are automatically extended unless terminated by either party.

Skookumchuck

Skookumchuck is a 137 MW wind facility that located in Lewis and Thurston counties, Washington. The facility began commercial operations in November 2020 and is secured by a long-term PPA with Puget Sound Energy Inc. that expires in 2040. Ninety-nine per cent of production tax credits are allocated to tax equity partners and the remainder are allocated to the Company and our partner Southern Power Company.

White Rock East and White Rock West

White Rock East and White Rock West are 201.5 MW and 99.5 MW wind facilities located in Caddo County, Oklahoma. On Dec. 22, 2021, TransAlta executed two long-term Power PPAs with Amazon for the offtake of 100 per cent of the generation from both facilities. White Rock West achieved commercial operation on Jan. 1, 2024 and White Rock East achieved commercial operation on April 22, 2024. The company has entered into two 10-year transfer agreements with A+ and AA- rated customers for the sale of 100 per cent of the expected production tax credits to be generated from the Horizon Hill, White Rock East, and White Rock West facilities. See the "General Development of the Business – Three-Year History" section of this AIF for further details.

Wyoming

Wyoming is a 140 MW wind facility located near Evanston, Wyoming. The facility began commercial operations in December 2003, and is contracted under a long-term PPA until 2028 with an investment-grade counterparty.

Australia Battery and Solar Facilities

Northern Goldfields Solar

Northern Goldfields Solar facilities consist of the 27 MW Mount Keith solar facility, 11 MW Leinster solar facility, 10 MW/5 MWh Leinster battery energy storage system facility and interconnecting transmission infrastructure, all of which are integrated into the existing Southern Cross Energy North remote electrical network in Western Australia. The combined solar and energy storage facilities began commercial operations in November 2023 and is contracted with BHP to 2038. See the "General Development of the Business" section of this AIF for further details.

Gas Segment

The Gas segment holds a net capacity ownership interest of 4,525 MW. The facilities are located in Alberta, Ontario, Michigan and Western Australia.

The following table summarizes our natural-gas-fired generation facilities as at Dec. 31, 2024:

Facility Name	Province/ State	Nameplate Capacity (MW)[1]	Consolidated Interest	Gross Installed Capacity (MW)[1]	Ownership	Net Capacity Ownership Interest (MW)[1]	Commercial Operation Date	Revenue Source[2]	Contract Expiry Date[3]
British Columbia									
McMahon	BC	120	50 %	60	100 %	60	1993	LTC	2029
Alberta									
Battle River 4	AB	155	100 %	155	100 %	155	1975	Merchant	-
Battle River 5	AB	395	100 %	395	100 %	395	1981	Merchant	-
Fort Saskatchewan	AB	118	60 %	71	50 %	35	1999	LTC/Merchant	2029
Joffre	AB	474	40 %	190	100 %	190	2000	LTC/Merchant	2041
Keephills Unit No. 2	AB	395	100 %	395	100 %	395	1984	Merchant	-
Keephills Unit No. 3	AB	466	100 %	466	100 %	466	2011	Merchant	-
Muskeg River	AB	202	100 %	202	100 %	202	2003	LTC	2042
Poplar Creek[4]	AB	230	100 %	230	100 %	230	2001	LTC	2030
Primrose	AB	100	50 %	50	100 %	50	1998	LTC	2028
Scotford	AB	195	100 %	195	100 %	195	2003	LTC/Merchant	2043
Sheerness Unit No.1	AB	400	100 %	400	75 %	300	1986	Merchant	-
Sheerness Unit No.2	AB	400	100 %	400	75 %	300	1990	Merchant	-
Sundance Unit No. 6	AB	401	100 %	401	100 %	401	1980	Merchant	-
Valleyview 1	AB	50	100 %	50	100 %	50	2001	Merchant	-
Valleyview 2	AB	50	100 %	50	100 %	50	2008	Merchant	-
Total Alberta Gas Capacity		**4,031**		**3,650**		**3,414**			
Ontario and United States									
Ada	MI	29	100 %	29	100 %	29	1991	LTC	2026
Ottawa	ON	74	100 %	74	50 %	37	1992	LTC/Merchant	2033
Sarnia	ON	499	100 %	499	100 %	499	2003	LTC	2031
Windsor	ON	72	100 %	72	50 %	36	1996	LTC/Merchant	2031
Total Ontario and United States Gas Capacity		**674**		**674**		**601**			
Australia									
Fortescue River Gas Pipeline	WA	N/A	100 %	N/A	43 %	N/A	2015	LTC	2035
Parkeston	WA	110	50 %	55	100 %	55	1996	LTC/Merchant	2027
South Hedland	WA	150	100 %	150	100 %	150	2017	LTC	2042
Southern Cross [5]	WA	245	100 %	245	100 %	245	1996	LTC	2038
Total Australian Gas Capacity		**505**		**450**		**450**			
Total Gas Capacity		**5,330**		**4,834**		**4,525**			

(1) MW are rounded to the nearest whole number. The gross installed capacity reflects the basis of consolidation of the underlying assets owned, whereas net capacity ownership interest deducts capacity attributable to non-controlling interest in these assets and is calculated after the consolidation of the underlying assets.

(2) The large majority of the Company's contracted operating facilities benefit from inflation-adjustment provisions that apply to all or a portion of our revenues under such contracts.

(3) Where no contract expiry date is indicated, the facility operates as merchant.

(4) The Poplar Creek faci ity is operated by Suncor Energy Inc. (Suncor)

(5) Includes four faci ities. Excludes the Northern Goldfields facilities, which are in the Wind and Solar segment.

British Columbia Gas Facilities

McMahon

The McMahon natural-gas-fired cogeneration facility is located in Taylor. The 120 MW McMahon facility has been in operation since 1993, and is fully contracted with Brookfield and NorthRiver Midstream for steam and BC Hydro for electricity through to 2029.

Alberta Gas Facilities

Battle River 4 and 5

The Battle River 4 and 5 facilities are located near Forestburg. Battle River 4 and 5 are 155 MW and 395 MW, respectively, having completed their conversion to natural gas in 2021 and 2019, respectively. The end of regulatory life for Battle River 4 and 5 is set for 2033 and 2037, respectively. Generation from the facilities is currently sold in the Alberta electricity market.

Fort Saskatchewan

We have a net ownership interest of 30 per cent in the Fort Saskatchewan facility. See the "Business of TransAlta – Non-Controlling Interests" section of this AIF for further details. The 118 MW natural-gas-fired combined-cycle cogeneration facility is owned by TA Cogen and Prairie Boys Capital Corporation. The contract at the facility has an initial 10-year term, which began on Jan. 1, 2020, with the option for two five-year extensions. Generation from the facility is currently sold in the Alberta electricity market.

Joffre

The Joffre natural-gas-fired cogeneration facility is located in Red Deer. TransAlta owns a 40 per cent interest in the facility, with Capital Power and Nova Chemicals owning 40 per cent and 20 per cent, respectively. The 474 MW Joffre facility has been in operation since 2000 and is 26 per cent (122 MW) contracted to Nova Chemicals through to 2041. The remaining uncontracted electricity capacity is sold in the Alberta energy market.

Keephills 2

The Keephills 2 facility is located approximately 70 kilometres west of Edmonton. Keephills 2 is a 395 MW gas-fired unit that completed its conversion to natural gas in 2021. The end of regulatory life for this unit is set for 2037. Generation from the facility is currently sold in the Alberta electricity market.

Keephills 3

The Keephills 3 facility is located approximately 70 kilometres west of Edmonton. Keephills 3 is a 466 MW gas-fired unit that completed its conversion to natural gas in 2021. The end of regulatory life for this unit is set for 2039. Generation from the facility is currently sold in the Alberta electricity market.

Muskeg River

The Muskeg River natural-gas-fired cogeneration facility is located in Fort McMurray. The 202 MW Muskeg River facility has been in operation since 2003 and is fully contracted to the Athabasca Oil Sands Project, which consists of Canadian Natural Resources Limited (CNRL), Chevron and Shell, through to 2042.

Poplar Creek

The Poplar Creek natural-gas-fired cogeneration facility is located in Fort McMurray. The Poplar Creek cogeneration facility had been built and contracted to provide steam and electricity to Suncor's oil sands operations. In 2015, Suncor acquired the Company's two steam turbines with an installed capacity of 126 MW and certain transmission interconnection assets. In addition, Suncor assumed full operational control of the cogeneration facility and has the right to use the full 230 MW capacity of the Company's gas generators until Dec. 31, 2030. The ownership of the Poplar Creek facility will transfer to Suncor on Dec. 31, 2030.

Primrose

The Primrose natural-gas-fired cogeneration facility is located near Bonnyville. TransAlta owns a 50 per cent interest with CNRL owning the remaining 50 per cent of the facility. The 100 MW Primrose facility has been in operation since 1998 and is fully contracted to CNRL through to 2028, at which time, will be transferred to CNRL at the expiry of the PPA with no remaining liabilities for TransAlta.

Scotford

The Scotford natural-gas-fired cogeneration facility is located in northeast of Fort Saskatchewan. The 195 MW Scotford facility has been in operation since 2003, and is fully contracted to CNRL, Chevron and Shell through to 2043.

Sheerness 1 and 2

The Sheerness 1 and 2 facilities are located approximately 200 kilometres northeast of Calgary. The 400 MW Sheerness 1 and 400 MW Sheerness 2 facilities are gas-fired units that completed their conversion to natural gas in 2021 and 2020, respectively. The end of regulatory life for these units is set for 2037. Generation from the facilities is currently sold in the Alberta electricity market.

Sundance 6

The Sundance 6 facility is located approximately 70 kilometres west of Edmonton. Sundance 6 is a 401 MW gas-fired unit that completed its conversion to natural gas in 2021. The end of regulatory life for this unit is set for 2037. Generation from the facility is currently sold in the Alberta electricity market. In November of 2024, the Company announced that the unit will be mothballed at the end of the first quarter of 2025.

Valleyview 1 and 2

The Valleyview 1 and 2 natural-gas-fired simple-cycle gas turbine generator facilities are located in Valleyview. The 50 MW Valleyview 1 and 50 MW Valleyview 2 facilities have been in operation since 2001 and 2008, respectively. Generation from the facilities is currently sold in the Alberta electricity market.

Off-Coal Agreement

On Nov. 24, 2016, we entered into the Off-Coal Agreement with the Government of Alberta pertaining to our cessation of emissions from the Keephills 3 and Sheerness coal-fired facilities. Under the Off-Coal Agreement, we are entitled to receive annual cash payments of approximately $41 million, net to TransAlta, from the Government of Alberta that commenced in 2017, and will terminate in 2030, subject to satisfaction of certain terms and conditions that include our cessation of all coal-fired emissions on or before Dec. 31, 2030. Other conditions include maintaining prescribed spending on investment and investment-related activities in Alberta, maintaining a significant business presence in Alberta (including through the maintenance of prescribed employment levels), maintaining spending on programs and initiatives to support the communities surrounding the facilities and the employees of the Company negatively impacted by the phase-out of coal generation, and the fulfilment of all obligations to affected employees, in each case as prescribed by the Off-Coal Agreement.

Eastern Canada and US Gas Facilities

Ada

Ada is a 29 MW contracted cogeneration facility located in Ada, Michigan. The facility has been in operation since 1991 and produces approximately 18,000 tonnes of steam hourly. The electricity and steam output of the facility are fully contracted until 2026 with Consumers Energy and Amway.

Ottawa

The Ottawa facility is owned by TA Cogen. See the "Business of TransAlta – Non-Controlling Interests" section of this AIF for further details. It is a 74 MW combined-cycle cogeneration facility located in Ottawa, Ontario. On Aug. 30, 2013, the Company announced the recontracting of the facility with the IESO for a 20-year term, effective January 2014. The Ottawa facility also provides thermal energy to the member hospitals and treatment centres of the Ottawa Health Sciences Centre and the National Defence Medical Centre. The thermal energy contract with the Ottawa Health Sciences Centre has a term to Dec. 31, 2033, with an automatic renewal of a five-year term unless terminated by either party.

Sarnia

The Sarnia cogeneration facility is a 499 MW combined-cycle cogeneration facility located in Sarnia, Ontario, that provides power and/or steam to nearby industrial facilities. The facility also provides electricity to the IESO under a contract that terminates on April 30, 2031, with the industrial customer contract terminations occurring from April 30, 2031, through Dec. 31, 2032.

Windsor

The Windsor facility is owned by TA Cogen. See the "Business of TransAlta – Non-Controlling Interests" section of this AIF for further details. It is a 72 MW combined-cycle cogeneration facility located in Windsor, Ontario. Effective Dec. 1, 2016, the Windsor facility began operating under an agreement with the IESO with a 15-year term for up to 72 MW of capacity. The Windsor facility also provides thermal energy to Stellantis Canada (formerly, FCA Canada, Inc. and Chrysler Canada) in Windsor under a contract that expires in 2028, with a series of six successive renewal terms of one year each.

Australian Gas Facilities

Fortescue River Gas Pipeline

In 2014, we established the Fortescue River Gas Pipeline joint venture with AGI Fortescue River Pty Limited. The joint venture (of which TransAlta is a 43 per cent partner) was successfully awarded the contract to design, build, own and operate the 270-kilometre Fortescue River Gas Pipeline, located in the Pilbara region of Western Australia, to deliver natural gas to Fortescue Metal Group's (FMG) Solomon facility. The pipeline was completed in the first quarter of 2015 and operates under a take-or-pay natural gas transport agreement with a subsidiary of FMG for an initial term of 20 years. The 16-inch diameter pipeline has an initial free-flow capacity of 64 terajoules per day. Under the gas tariff agreement, FMG has the option to purchase the Fortescue River Gas Pipeline commencing March 2020. FMG maintains its option and the joint venture continues to deliver natural gas to the Solomon facility.

Parkeston

The Parkeston facility is a 110 MW dual-fuel natural gas- and diesel-fired power station located near Kalgoorlie, Western Australia, which is owned in partnership through a 50/50 joint venture with Northern Star (NPK) Pty Ltd., a subsidiary of Northern Star Resources Limited. The Parkeston facility primarily supplies energy to Kalgoorlie Consolidated Gold Mines pursuant to a supply contract that extends to October 2027. Any merchant capacity and energy are sold in Western Australia's wholesale electricity market.

South Hedland

The South Hedland Power Station is a 150 MW combined-cycle power station located near South Hedland, Western Australia, which achieved commercial operation in 2017. The facility is contracted with two customers. Horizon Power, the state-owned electricity supplier in the region has contracted 110MW until 2042. The second customer is the port operations of FMG for 35 MW of capacity until 2037.

Southern Cross Energy

Southern Cross Energy Partnership (SCE) has power stations at Mount Keith, Leinster, Kalgoorlie and Kambalda. In total, a combined gas- and diesel-fired capacity of 245 MW is available from these facilities. In 2023, SCE added battery and renewable energy capacity to the SCE fleet with separate solar facilities at Leinster (11 MW) and Mount Keith (27 MW), as well as a battery energy storage system at Leinster (10 MW/5 MWh). SCE also completed the expansion of the Mount Keith 132kV transmission system to support BHP's Northern Goldfields-based operations in the first quarter of 2024.

The PPA with BHP for the facilities expires on Dec. 31, 2038. The PPA provides, among other things, SCE with the exclusive right to supply electricity, transmission, and distribution infrastructure for BHP's mining operations located within a specified area in the Goldfields region of Western Australia for the duration of the PPA.

The PPA supports BHP's future power requirements and emission reduction targets by providing BHP participation rights in integrating renewable electricity generation, including solar, wind and energy storage technologies, into BHP's mining operations located in the Goldfields region, subject to the satisfaction of certain conditions. New-build projects have already been completed under this contract, including the Northern Goldfields solar and battery project in Mount Keith and Leinster that reached commercial operation in November 2023. Additional projects are in the development and construction stages. See the "General Development of the Business" section of this AIF for further details.

On July 11, 2024, BHP announced a period of temporary suspension of operations for its Western Australian nickel operations in response to the low nickel price outlook. The PPA remains in place and SCE is working closely with BHP to manage the impact of reduced load. BHP intends to review the decision to temporarily suspend its Western Australian nickel operations by February 2027.

Energy Transition Segment

The Energy Transition segment holds a net ownership interest in 671 MW of generating capacity. The two facilities are located in the United States.

The following table summarizes our Energy Transition facilities as at Dec. 31, 2024:

Facility Name	Province/ State	Nameplate Capacity (MW)[1]	Consolidated Interest	Gross Installed Capacity (MW)[1]	Ownership	Net Capacity Ownership Interest (MW)[1]	Commercial Operation Date	Revenue Source	Contract Expiry Date
US									
Centralia	WA	670	100 %	670	100 %	670	1971	LTC/Merchant	2025
Skookumchuck[2]	WA	1	100 %	1	100 %	1	1970	LTC	2025
Total Energy Transition Capacity		**671**		**671**		**671**			

(1) MW are rounded to the nearest whole number. The gross installed capacity reflects the basis of conso idation of underlying assets owned, whereas net capacity ownership interest deducts capacity attributable to non-controlling interest in these assets and is calculated after consolidation of underlying assets.

(2) This facility is used to provide a reliable water supply to the Centra ia faci ity.

Centralia

The Centralia coal-fired facility is located in Centralia, Washington, and consists of one 670 MW unit. On July 25, 2012, we announced that we entered into an 11-year PPA to provide electricity from the Centralia thermal facility to Puget Sound Energy. The contract terminates on Dec. 31, 2025 when the facility is scheduled to stop burning coal. Under the agreement, Puget Sound Energy purchases 380 MW of baseload power to December 2024 and 300 MW in 2025. The coal used to fuel the Centralia facility is sourced from the Powder River Basin in Montana and Wyoming. The Centralia facility has coal contracts in place that expire at the end of 2025.

We sell electricity from the Centralia thermal facility into the Western Electricity Coordinating Council and, in particular, to the U.S. Pacific Northwest electricity market. Our strategy is to balance contracted and non-contracted sales of electricity to manage production and price risk.

Since 2015, we have invested US$55 million to support energy efficiency, economic and community development, and education and retraining initiatives in Washington State. The initiatives are part of Centralia's transition from coal-fired operations in Washington, beginning on Dec. 31, 2020. Such community investment is part of the *TransAlta Energy Transition Bill (chapter 180, Laws of 2011)* (the Bill). The Bill was an agreement between policymakers, environmentalists, labour leaders and TransAlta to transition away from coal in Washington State.

Skookumchuck Hydro

We own a 1 MW hydroelectric generating facility that is located on the Skookumchuck River near Centralia, Washington, and related assets that are used to provide water supply to our generation facilities in Centralia. On Dec. 7, 2020, we entered into a PPA with Puget Sound Energy for the Skookumchuck hydro facility. The contract terminates in 2025 when the facility is scheduled to retire.

Reclamation Activities

Centralia Mine

We own a coal mine adjacent to the Centralia facility, although mining operations were discontinued at the Centralia coal mine on Nov. 27, 2006. The mine is currently in the reclamation phase and we continue to perform reclamation and associated work.

Under the U.S. *Federal Mine Safety and Health Act*, we must report all citations at our Centralia mine. There was one injury incident reported at the mine during 2024. The total dollar value of all Mine Safety and Health Administration (MSHA) assessments is not material.

Mine or Operating Name/MSHA Identification Number	Total Number of Section 104 Violations for which Citations Received	Total Number of Orders Issued Under Section 104(b)	Total Number of Citations and Orders for Unwarrantable Failure to Comply with Mandatory Health or Safety Standards Under Section 104(d)	Total Number of Flagrant Violations Under Section 110(b)(2)	Total Number of Imminent Danger Orders Issued Under Section 107(a)	Total Dollar Value of MSHA Assessments Proposed	Total Number of Mining Related Fatalities	Received Notice of Pattern Violations Under Section 104(e) (yes/no)	Received Notice of Potential to Have Pattern Under Section 104(e) (yes/no)	Number of Legal Actions Initiated or Pending During Period
4500416	10[1]	0	0	0	0	1,430 [2]	0	No	No	0

(1) Section 104 Violations: TransAlta Centra ia Mining (9 violations) and Dickson Company (contractor) (1 violation).

(2) Citations in Contest: Coalview Centra ia LLC ($1,287) and Dickson Company ($143).

Highvale Mine

We own the Highvale mine that supplied coal to the previously coal-fired Sundance and Keephills facilities. The Company discontinued all mining operations at the Highvale mine at the end of 2021 and the mine is currently in the reclamation phase as of Jan. 1, 2022.

Coal Retirements

In aggregate, TransAlta has retired 4,464 MW of coal-fired generation capacity since 2018 while converting 1,659 MW to cleaner-burning natural gas. The following seven units have been retired: Centralia Thermal No. 1, Keephills 1, and Sundance 1, 2, 3, 4 and 5. The retirements remain consistent with our strategy to transition to clean electricity. Pursuant to the Bill, Centralia Unit 2 will cease operation on coal effective Dec. 31, 2025.

Energy Marketing Segment

Our Energy Marketing segment provides a number of strategic functions, including the following:

- Gathering and analyzing market trends to enable more effective strategic planning and decision-making;
- Actively engaging in the trading of power, natural gas and environmental products across a variety of North American markets, excluding Alberta;
- Negotiating and managing fuel supply arrangements with third parties for our generation assets, including scheduling, billing and settlement of physical deliveries of natural gas and other fuels; and
- Negotiating and entering into contractual agreements with customers for the sale of output from our generation assets outside of Alberta, including electricity, steam or other energy-related commodities.

The Energy Marketing segment derives all of its revenue by trading electricity and other energy commodities (i.e., fuels and environmental products), by providing fee-based asset management services to third parties and earning margins on third-party gas and power transactions. The origination and trading activities are primarily focused on proprietary trading, with additional focus on the existing assets and customers of the Company.

The key risk control activities of the Energy Marketing segment include the measurement and management of market, credit, operational, reputational, compliance and legal risks. The segment uses value at risk, gross margin at risk and tail risk measures to monitor and manage the risks within our asset and trading portfolios. Value at risk and gross margin at risk measure the potential losses that could occur over a given time period due to changes in market risk factors. Back tests are used to provide further sensitivities to the market risks within the portfolio. Compliance, goodwill and legal risks are managed within our legal and compliance policies, and monitoring tools are used to flag compliance risks. The Energy Marketing segment actively manages the risks within approved limits of our governance policies.

Corporate Segment

Our Corporate segment includes the Company's finance, sustainability, legal, human resources, administrative, business development and investor relations functions.

Non-Controlling Interests

Our operations in which we have non-controlling interests are as follows:

TA Cogen

We hold a 50.01 per cent limited partnership interest in TA Cogen, which is an Ontario limited partnership. The remaining 49.99 per cent is held by CPH Cogen Inc., a subsidiary of CK Infrastructure Holdings Limited.

TA Cogen holds a 50 per cent interest in the 800 MW Sheerness dual-fuel generating facility in Alberta and a 60 per cent interest in the 118 MW Fort Saskatchewan natural-gas-fired cogeneration facility in Alberta. TA Cogen also holds an interest in two natural-gas-fired cogeneration facilities located in Ontario: the 74 MW Ottawa plant and the 72 MW Windsor plant. See the "Gas Segment" section of this AIF for further details.

Kent Hills Wind LP

We hold an 83 per cent partnership interest in Kent Hills Wind LP, which owns and operates the 167 MW Kent Hills (1, 2 and 3) wind facilities located in New Brunswick. The remaining 17 per cent is held by Natural Forces Technologies Inc., a wind developer based in Atlantic Canada that helped develop the Kent Hills wind projects with TransAlta.

Competitive Environment

Power generation is an industry in the midst of an exciting transformation and the demand for electricity has the potential to grow significantly over the long-term due to general trends toward electrification. We also anticipate the generation mix to undergo a major shift in our key markets. In addition to the need to keep pace with ongoing demand growth for electricity, there are several key factors driving the need for significant investment in new generating capacity, which include, without limitation:

- Coal-based generation is being retired. These retirements are being driven by asset age, as well as government policy that places an escalating price on GHG emissions and, in some cases, mandates the retirement of these assets;
- Government policies that impose costs or provide incentives for lower emission technologies are creating opportunities for renewable generation technologies. These opportunities are coinciding with a significant decline in the installed costs of wind and solar generation and battery storage. As a result, these technologies now account for the majority of the new generating capacity added to many of the world's electricity grids;
- In tandem, the need and value of reliability within electricity systems across TransAlta's portfolio is becoming an important focus for system operators and customers. Opportunities for legacy gas-fired generation are being identified as systems seek to balance renewable demands with the need for reliable generation; and
- Growing electricity demand, from electrification and data centre development, is driving load growth. Electrification is seen as one of the most effective levers to reduce GHG emissions in many sectors, such as transportation. In tandem, growing demand related to artificial intelligence and data centre development is resulting in expanded load forecasts.

Alberta

Approximately 58 per cent of our gross installed capacity is located in Alberta. As of Dec. 31, 2024, our portfolio of merchant assets in Alberta is a combination of hydro facilities, wind facilities, a battery storage facility, natural-gas-fired cogeneration and converted natural-gas-fired thermal facilities. This balance of fuel types provides us with portfolio generation diversification, along with capacity that can be monetized as ancillary services or dispatched into the energy market during times of supply tightness. To reduce the exposure from variable spot power prices on our merchant generation, we enter into financial hedges and/or physical retail supply contracts through our Commercial and Industrial Business. The combined liquidity provided by these channels enables us to actively secure revenue, and respond to changing market conditions and adjust the proportion of our hedges we have in relation to the expected generation from our asset portfolio.

Alberta's annual electricity demand increased from 2023 to 2024 by approximately three per cent. The average pool price in Alberta declined from $134/MWh in 2023 to $63/MWh in 2024. While demand growth was

positive, lower natural gas prices and supply additions - renewables, natural gas and cogeneration - meant the market was more supplied as compared to 2023.

We currently expect additional compliance costs as a result of the Canadian federal government's *Greenhouse Gas Pollution Pricing Act* (GGPPA), which sets a national price on GHG emissions with each province expected to implement a GHG policy equivalent to a carbon price of $170 per tonne by 2030. We believe our portfolio of assets provides us with brownfield development opportunities in wind, solar, hydro and natural gas that give us an advantage over competitors when constructing generation facilities that use these fuel types.

US Pacific Northwest

Our generating capacity in the U.S. Pacific Northwest includes the remaining Centralia coal unit and our 49 per cent interest in the Skookumchuck wind facility. The Centralia coal unit is scheduled to be legislatively retired on Dec. 31, 2025.

System capacity in the region is primarily composed of hydro and gas generation, with some wind additions over the last few years in response to government programs favouring renewable generation. Demand growth in the region has been limited and further constrained by an emphasis on energy efficiency. We expect to see significant change in this market over the next decade as coal generation is retired and renewable portfolio standard requirements continue to strengthen.

Our competitiveness is enhanced by our contract with Puget Sound Energy for up to 300 MW over the remaining life of the Centralia facility. The contract and our hedges allow us to satisfy power requirements from the market during low-priced periods. The Centralia site also holds potential value for future redevelopment opportunities given its access to existing infrastructure and transmission interconnection.

Australia

Our business is solely in Western Australia, and is focused on the large, remote mining industry in the state. The primary exports from Western Australia are iron ore, natural gas and gold. Commodity exports from Western Australia contribute significantly to the economy, driven by large-scale creditworthy producers. Remote mining operations are exploring options to add renewable generation with firming options via thermal generation and battery energy storage systems to their existing and new sites in an effort to reduce the amount of gas and diesel required in these operations. We expect this trend to continue and to create further opportunities for our business in Western Australia.

Contracted Gas and Renewables

We develop and acquire gas and renewable generation facilities in highly competitive markets. Our track record as an experienced operator and developer supports our competitive position. Where possible, we aim to reduce our cost of capital and improve our competitive profile through efficient financing structures. In the United States, our substantial tax attributes further increase our competitiveness.

In renewables, we are primarily evaluating greenfield opportunities in Western Canada and the United States along with acquisitions in markets where we have existing operations. We maintain highly qualified and experienced development teams to identify and develop these opportunities. In cogeneration, we are working with experienced development and construction teams to evaluate behind-the-fence solutions.

Some of our older gas facilities are now reaching the end of their original contract life. These facilities generally have a substantial cost advantage over new builds and we have been able to add value by recontracting these facilities without incurring the significant capital expenditures required for a new facility.

Seasonality and Cyclicality

Our business is cyclical due to: (a) the nature of electrical generation and the limited storage capacity; and (b) the nature of wind, solar and run-of-river hydroelectric resources, which fluctuate based on both seasonal patterns and annual weather variation.

Typically, run-of-river hydroelectric facilities and solar facilities generate most of their electricity and revenues during the spring and summer months when the melting snow starts feeding the watersheds and the rivers, and the sun is at its peak. Inversely, wind speeds are historically greater during the cold winter months when the air density is at its peak. Our strategy of technological and geographical diversification reduces our exposure to the variations of any one natural resource in any regions. Financial results in any one quarter may not, however, be representative of all quarters. See the "Risk Factors" section of this AIF for further details.

Regulatory Framework

Below is a description of the regulatory framework in the markets that are material to the Company.

Canadian Federal Government

In November 2016, the Canadian federal government announced that coal-fired generation would be phased out by 2030, following a similar commitment by the Alberta provincial government in November 2015. On Dec. 12, 2018, Environment and Climate Change Canada (ECCC) published two final regulations in the Canada Gazette, Part II to phase out coal-fired generation by 2030, as well as regulations for gas-fired electricity generation including provisions for the conversion of boiler units from coal-fired generation to natural-gas-fired generation. In addition, the *Clean Electricity Regulations* (CER), issued by the Canadian federal government on Dec. 17, 2024, impose further emission limits on electricity generation facilities in Canada. See the "Environmental Risk Management – Climate-Related Financial Disclosure" and "Environmental Risk Management – Canadian Federal Government" sections of this AIF for further details.

Alberta

Alberta operates under a competitive wholesale energy-only market structure where generators offer their power supply into a power pool and those offers clear against power demand. Market clearing prices are determined by the dynamics of supply and demand in the wholesale electricity market. Since the first quarter of 2024, the Government of Alberta and the AESO have advanced a Restructured Energy Market (REM) that will replace the existing market design and is expected to be implemented in 2027.

On July 3, 2024, Alberta's Minister of Affordability and Utilities issued a letter to the AESO identifying a proposed high-level design for the REM that includes: (i) a mandatory day-ahead market; (ii) a review of the wholesale electricity market price floor and price cap; (iii) a uniform system-wide market price; (iv) co-optimization of the energy and ancillary services markets; and (v) optimization of dispatch around transmission constraints. The REM contemplates additional changes that will impact the Alberta energy market including a move away from the congestion-free planning paradigm to an "optimally planned transmission standard" as well as a strategic reserve mechanism to contract with out-of-market generation for reliability purposes. The AESO commenced detailed design sessions in consultation with industry stakeholders in October 2024 and issued a High-Level Design Proposal for the REM for stakeholder comment in December 2024. Development of the detailed REM is scheduled to take place in the first quarter and early in the second quarter of 2025. The provincial government plans to propose legislative changes to enable the REM in spring 2025, which will be followed by AESO market rule development activities between December 2025 and December 2026 before REM is implemented in 2027.

The Government of Alberta also continues to make changes to the policy framework for the development of renewable energy facilities. This work follows the government's pause on the issuance of power plant approvals for new renewable energy facilities that occurred between Aug. 3, 2023 and Feb. 29, 2024, and the recommendations stemming from the Alberta Utilities Commission inquiry that occurred during that time. On Dec. 6, 2024, the government issued a new *Electric Energy Land Use and Visual Assessment Regulation* that establishes visual impact assessment requirements for renewable energy facilities proposed within buffer zones and visual impact assessment zones and agricultural impact assessment requirements for renewable energy facilities proposed on high-quality agricultural lands (Class 1 and 2 lands, and Class 3 lands in certain

areas). The Government of Alberta is also amending the *Activities Designation Regulation* and *Conservation and Reclamation Regulation* to require renewable energy operators to post security with the Government of Alberta that is sufficient to cover estimated decommissioning and reclamation costs, or provide evidence that such security has been provided to the application landowner(s) pursuant to a surface lease.

Ontario

Ontario's electricity market is a hybrid market that includes a wholesale electricity market, as well as regulated prices for certain electricity consumers and long-term contracts for the purchase of power by the IESO from power producers. The Ontario Ministry of Energy and Electrification supports the IESO in defining the electricity mix to be procured by the IESO. The IESO has the mandate to undertake long-term planning of the electric power system, procure the electricity generation in that plan and manage contracts for privately owned generation. The IESO is responsible for managing the Ontario wholesale market and ensuring the reliability of the electricity system in Ontario. The electricity sector is regulated by the Ontario Energy Board.

The IESO is currently in the stages of market manual development and settlement rule testing, finalization and approval, with the intent to implement the Market Renewal Program in the second quarter of 2025. The program includes the introduction of a day-ahead market, locational pricing, enhanced unit commitment and market power mitigation. The impact on existing facilities is mitigated due to existing contracts and related proposed amendments that account for the impacts of the Market Renewal Program (e.g., capacity contracts for gas facilities and wind power purchase arrangements for wind facilities). The IESO is coordinating its changes to its energy market with new resource adequacy procurements, including new contract types for medium- and long-term requests for proposals, re-contracting with existing facilities (small hydro re-contracting) and improving market operations and reliability. Our Ontario facilities are generally contracted, and therefore we expect market rule changes to have minimal near-term impact on the Company.

U.S. Wholesale Power Market

The *Federal Power Act* gives the Federal Energy Regulatory Commission (FERC) rate-making jurisdiction over public utilities engaged in wholesale sales of electricity and the transmission of electricity in interstate commerce. FERC oversees the market structure for all integrated market rules and wholesale sales from generators. The *Federal Power Act* also provides FERC with the authority to certify and oversee an electric reliability organization that promulgates and enforces mandatory reliability standards applicable to all users, owners and operators of the bulk power system. FERC has certified the North American Electric Reliability Corporation (NERC) as the electric reliability organization. NERC has promulgated mandatory reliability standards and, in conjunction with the regional reliability organizations that operate under FERC's and NERC's authority and oversight, enforces those mandatory reliability standards.

Regulatory changes are not expected to have a material impact in the near term on generation from our facilities in Minnesota, Massachusetts, New Hampshire, North Carolina, Oklahoma, Pennsylvania and Wyoming as generation from these facilities is fully contracted to creditworthy counterparties.

Washington

Centralia and Skookumchuck are operated in the state of Washington. The Washington Transportation and Utilities Commission (WTUC) has the power to regulate and supervise every "public utility," which includes investor-owned electric utilities. For regulated electric utilities, the WTUC approves regulated rates, reviews integrated resource plans, approves mergers and acquisitions, and grants certificates of public convenience and necessity for large facilities (i.e., power plants and transmission lines). The Centralia facility, the Skookumchuck hydro facility and the Skookumchuck wind facility are not regulated by the WTUC as they only sell wholesale electricity and do not sell retail electricity in the state. Only FERC and NERC requirements apply to these facilities. As a result, the Company does not expect any material impacts on revenue streams from any decisions of the WTUC.

Australia

Australia has two separate major electricity markets: the National Electricity Market (NEM) encompassing all the major population centres on the eastern seaboard and the Wholesale Electricity Market (WEM) covering the southwest of Western Australia including its capital city, Perth. A number of smaller, standalone electricity grids serve regional population centres including the North West Interconnected System (NWIS) in the Pilbara region of Western Australia and the Darwin-Katherine System in the Northern Territory.

The Australian Energy Market Operator is the market operator for both the WEM and the NEM. The two markets are completely independent of each other with different market rules and no physical interconnection between them. The WEM includes both a market for generation capacity and a gross pool to trade energy with a single reference node for wholesale prices. The NEM is a pure energy-only market with five regional reference nodes for wholesale prices corresponding to each of the participating states of Queensland, New South Wales, Victoria, Tasmania and South Australia.

In October 2023, significant reforms to the WEM were implemented, including security constrained dispatch in the energy market and the introduction of additional ancillary services to support the transition to renewable energy sources.

Reforms to the NWIS have been gradually implemented, including providing third-party access to the transmission networks, coordination of outage planning and ensuring generation adequacy.

Environmental Risk Management

We are subject to federal, provincial, state and local environmental laws, regulations and guidelines concerning the generation and transmission of energy. We are committed to complying with legal requirements and to minimizing the environmental impact of our operations. We work with governments, stakeholders and the public to develop appropriate frameworks to protect the environment, as well as to promote sustainable development.

Climate-Related Financial Disclosure

We have prepared an assessment of climate-related risks and opportunities to partially align with the IFRS S2 Climate-related Disclosures Standard and Task Force on Climate-related Financial Disclosures describing our climate change strategy, governance, risk management approach, metrics and targets. In 2024, we reviewed and updated our climate transition plan and prepared climate-related financial metrics. See the "Sustainability" section of the 2024 Integrated Report for further details.

Canada

Federal Carbon Pricing and Regulations on GHG Emissions

On June 21, 2018, the Canadian federal GGPPA came into force. Under the GGPPA, the Canadian federal government implemented a national price on GHG emissions. In April 2021, the Government of Canada announced a revised GHG emissions target of 40 to 45 per cent below 2005 levels by 2030. Amendments to the GGPPA were completed in October 2022 to align facility emission charges with the government's updated carbon price trajectory of $65 per tonne of carbon dioxide equivalent (CO_2e) in 2023 with increases of $15 per year to $170 per tonne by 2030.

In March 2022, the Government of Canada's Department of ECCC released a discussion document regarding the CER to achieve a net-zero electricity sector in Canada by 2035. The draft CER was published in Canada Gazette I in August 2023 and the finalized regulations were issued under the *Canadian Environmental Protection Act, 1999* on Dec. 17, 2024. The CER imposes an annual emissions limit (AEL) on electricity generation units that use fossil fuels based on each unit's generation capacity, its annual hours of operation and an applicable emissions intensity. The applicable emissions intensity is 65 tonnes of CO_2e/GWh between 2035 and 2049, during which time regulated units may emit up to 35 t/GWh above the AEL by remitting an equivalent amount of eligible offset credits. The applicable emissions intensity is reduced to 0 t/GWh as of 2050, but up to 42 t/GWh of emissions are permitted, subject to remitting an equivalent amount of eligible offset credits. Eligible offset credits include those issued or recognized under the GGPPA regime, including several TIER offset protocols. Subject to limited exceptions, the AEL will apply to most generating units as of Jan. 1, 2035. At this time, TransAlta does not expect the CER to have a material impact on its business.

In addition to carbon pricing and the CER, the Canadian federal government continues to further develop federal incentives for renewable generation and new and emerging technology and infrastructure. We continue

to actively engage with the Canadian federal government to understand the implications of these initiatives to our business in order to manage risks and identify opportunities.

Oil and Gas Sector Greenhouse Gas Emissions Cap

In December 2023, the Canadian federal government introduced a draft framework to cap emissions from the oil and gas sector. Consultation on the draft framework has been ongoing since that time. The draft Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations were introduced on Nov. 4, 2024. The proposed regulations would set a cap on GHG emissions within the sector, equivalent to 35 per cent below 2019 levels and create a cap and trade system to incentivize emission reductions and facilitate compliance across the sector. While the proposed cap-and-trade system is expected to allow for cross-recognition of offset credits from other emission reduction regimes, the interplay between the proposed cap-and-trade system and regulations like TIER remains unclear. The public comment period for the draft regulations closed on Jan. 8, 2025, and the government is expected to publish final regulations later in 2025. Given that the use of provincial offsets as a compliance mechanism has implications for TransAlta, we will continue to follow developments and engage where appropriate in the development of the final regulations.

Alberta

Large Emitter Greenhouse Gas Regulations

Facilities with emissions above the set benchmark must comply with TIER by: (a) paying into the TIER Fund (a provincial government-controlled fund that invests in emissions reductions in the province) at the current carbon price; (b) making emission reductions at their facility; (c) remitting EPCs from other facilities; or (d) remitting emission offset credits.

On Dec. 15, 2022, amendments to TIER and the *Administrative Penalty Regulation* were announced to ensure alignment with the Canadian federal government's requirements under the GGPPA, which included the following changes:

- The TIER Fund price for the 2023 to 2030 period was set via a Ministerial Order. The price was set at $65 per tonne of CO_2e in 2023, increasing by $15 per tonne CO_2e annually to $170 per tonne CO_2e by 2030;
- Starting in 2023, a two per cent annual tightening rate will apply to the electricity high performance benchmark from 0.3626 CO_2e tonnes per MWh in 2023 to 0.3108 CO_2e tonnes per MWh in 2030;
- The maximum allowable emissions offsets, emissions performance standards or sequestration credits that can be used by a given facility in a year was set to 60 per cent in 2023, 70 per cent in 2024, 80 per cent in 2025, and 90 per cent in 2026 and beyond; and
- EPCs issued in 2023 or a subsequent year may only be used within the five-year period after the EPC was issued, while offsets may only be used within a six-year period, including the reduction year.

These changes will result in lower emissions offset crediting for new renewables projects but, all things being equal, should also result in higher demand for emissions offset credits from TransAlta's renewables facilities. TransAlta's gas-fired facilities will face more stringent performance standards. TIER will remain in effect through 2030 and will be reviewed on or before Dec. 31, 2026.

Ontario

Large Emitter Greenhouse Gas Regulations

As of Jan. 1, 2022, the Emissions Performance Standards (EPS) system applies in Ontario and the federal Output-Based Performance Standards no longer directly applies to covered emitters.

In December 2022, Ontario announced changes to the EPS to ensure alignment with the Canadian federal government's requirements under the GGPPA. Two electricity-related changes will impact TransAlta's gas-fired facilities in Ontario:

- Changing the electricity performance standard from 0.37 tonnes CO_2e per MWh in 2022 to 0.31 tonnes CO_2e per MWh starting in 2023, remaining flat to 2030; and

- Allowing cogeneration units to utilize separate performance standards for electricity and heat to enable a level playing field for all electricity under the EPS.

The change in cogeneration performance standard treatment will benefit TransAlta's facilities by removing a previous, single cogeneration standard that was more stringent than using separate standards for heat and electricity. The value from this change flows to contracted customers but helps make cogeneration more competitive as an energy solution.

Ontario is continuing its work on the natural gas transition and has developed a voluntary clean energy credit market for specified asset types directly connected to the IESO grid or a distribution system. TransAlta will continue to engage the government on relevant policy initiatives to mitigate risk and identify areas of potential opportunity.

United States

Following the inauguration of President Trump on Jan. 20, 2025, the President signed an Executive Order, directing the withdrawal of the United States from the Paris Agreement. It is expected that the United States may reduce current climate commitments; however, state level governments may choose to retain targets if this occurs. Existing commitments for carbon emissions reductions, include: achieving a 50 to 52 per cent national emissions reduction below 2005 levels by 2030, a net-zero electricity grid by 2035 and a net-zero national economy by 2050. Although the United States does not have a national carbon pricing regime, it currently offers federal incentives for renewable generation and new technology and infrastructure, including spending under the *Inflation Reduction Act*.

State and regional climate and market policies have a significant impact on the pace of energy transition in the United States, with many state governments operating under renewable portfolio standards and carbon pricing regimes. Similar to Canada, independent estimates suggest that the United States will require substantial growth in zero-emissions generation to meet its national climate targets.

Washington State

Large Emitter Cap and Trade Program

In 2010, the Washington Governor's Office and Department of Ecology negotiated agreements with TransAlta to retire Centralia's two coal-fired electricity generating units, one in 2020 and the other in 2025. This agreement is formally part of the state's climate change program. We currently believe that there will be no additional GHG regulatory burden on Centralia given these commitments. The related TransAlta Energy Transition Bill was enacted in 2011 and provides a framework to transition from coal to other forms of generation in the State of Washington.

On May 17, 2021, Governor Inslee signed Washington State's *Climate Commitment Act*. which came into effect on Jan. 1, 2023. This law covers entities that emit over 25,000 tonnes of CO_2e per year. It creates a "cap-and-invest" program, which sets a state-wide cap on GHG emissions and then auctions or allocates emissions allowances. TransAlta's Centralia coal facility will be exempt from the cap-and-invest program until it closes in 2025, as per the agreement with the state of Washington. The Washington Department of Ecology held quarterly auctions for compliance in 2024. The auctions offered 2023 and 2024 vintage allowances, and an advance auction of 2027 vintage allowances. TransAlta continues to track the cap-and-invest program as it develops and moves into its second year of implementation. The Company will engage when necessary with relevant government departments should there be any future implementation changes that impact our operations or energy trading in Washington.

Australia

In October 2021, the Australian government announced a target to reach net-zero emissions by 2050. Following the May 2022 federal election, the elected Labor government enacted a more ambitious near-term target through the *Climate Change Act 2022*, which commits Australia to a 43 per cent emissions reduction below 2005 levels by 2030. The government also confirmed its intent to boost renewable electricity production to 82 per cent of the electricity supply by 2030. Large GHG emitters are required to reduce their scope 1

emissions under the Australian Government's National Safeguard Mechanism (SGM). While the government has made recent changes to the SGM, these changes are not expected to have a material impact on TransAlta's assets.

The Australian government's plan to achieve the necessary reductions is focused on a combination of technology development and cost reduction, enabling deployment at scale through incentives and infrastructure development as well as updating some of its regulatory mechanisms. In particular, an AU$20 billion fund has been set aside to support infrastructure investment, such as transmission network reinforcement, and enable the shift to renewables. Decarbonization efforts have been centred on funding for clean technologies, upgrading the electricity grid to support more renewables, regulating and reporting of GHGs, and incentivizing zero-emission vehicle adoption.

Australian state-level policies continue to focus on moving toward greater reliance on renewables, hydrogen and energy storage and away from coal.

TransAlta does not see any significant risk to our existing Australian assets. Policy and funding supporting continued industrial decarbonization could provide additional growth opportunities in the Australian market.

TransAlta Activities

Reducing the environmental impact of our activities benefits not only our operations and financial results, but also the communities in which we operate. We expect that increased scrutiny will continue to be placed on GHG emissions and compliance. We take a proactive approach to minimizing environmental and safety risks to our results. The board of directors of the Company (the Board or the Board of Directors) provides oversight to our environmental management programs and emissions reduction initiatives in order to ensure continued compliance with environmental regulations.

For a description of our environmental management system and other aspects of our environmental strategy see the "Managing Environmental Resources" section of the MD&A, which is incorporated by reference herein.

Emission Offset Portfolio

TransAlta also maintains a GHG emissions offset portfolio with a variety of instruments that can be used for compliance purposes or otherwise banked or sold. We continue to examine additional emission offset opportunities that also allow us to meet our emissions compliance obligations at a competitive cost. We invest in offsets that we expect will meet certification criteria in the market in which they are to be used.

Risk Factors

For a discussion of risk factors affecting TransAlta, see the "Governance and Risk Management" section of the MD&A, which is incorporated by reference herein.

Employees

The Company is required to develop and retain a skilled workforce for its operations. Many of TransAlta's employees possess specialized skills and training and we must compete in the labour market for these workers. As at Dec. 31, 2024, we had 1205 active employees, which includes full-time, part-time and temporary employees. Approximately 29 per cent of our employees are represented by labour unions. We are currently a party to 12 different collective bargaining agreements. As at Dec. 31, 2024, women accounted for 28 per cent of all employees and 32 per cent of our executive team.

For a description of social policies implemented by TransAlta please see "Engaging with Our Stakeholders to Create Positive Relationships" and "Building a Diverse and Inclusive Workforce" sections of the MD&A which are incorporated by reference herein.

Capital Structure

Share Capital

Our authorized share capital consists of an unlimited number of common shares and an unlimited number of first preferred shares, issuable in series. For the number of common shares and first preferred shares issued and outstanding as at Dec. 31, 2024, see the "Financial Capital – Share Capital" section of the MD&A, which is incorporated by reference herein.

Common Shares

Each common share of the Company entitles the holder thereof to one vote for each common share held at all meetings of shareholders of the Company, except meetings at which only holders of another specified class or series of shares are entitled to vote, to receive dividends if, as and when declared by the Board of Directors, subject to prior satisfaction of preferential dividends applicable to any first preferred shares, and to participate rateably in any distribution of our assets upon a liquidation, dissolution or winding up and subject to prior rights and privileges attaching to first preferred shares. The common shares are not convertible and are not entitled to any pre-emptive rights. The common shares are not entitled to cumulative voting.

First Preferred Shares

We are authorized to issue an unlimited number of first preferred shares, issuable in series and, with respect to each series, the Board of Directors is authorized to fix the number of shares comprising the series and determine the designation, rights, privileges, restrictions and conditions attaching to such shares, subject to certain limitations.

The first preferred shares of all series rank senior to all other shares of the Company with respect to priority in payment of dividends and with respect to distribution of assets in the event of liquidation, dissolution or winding up of the Company, or a reduction of stated capital. Holders of first preferred shares are entitled to receive cumulative quarterly dividends on the subscription price thereof as and when declared by the Board of Directors at the rate established by the Board of Directors at the time of issue of shares of a series. No dividends may be declared or paid on any other shares of the Company unless all cumulative dividends accrued upon all outstanding first preferred shares have been paid or declared and set apart. In the event of the liquidation, dissolution or winding up of the Company, or a reduction of stated capital, no sum shall be paid or assets distributed to holders of other shares of the Company until the holders of first preferred shares shall have been paid the subscription price of the shares, plus a sum equal to the premium payable on a redemption, plus a sum equal to the arrears of dividends accumulated on the first preferred shares to the date of such liquidation, dissolution, winding up or reduction of stated capital, as applicable. After the payment of such amount, the holders of first preferred shares shall not be entitled to share further in the distribution of our assets.

The Board of Directors may include, in the share conditions attaching to a particular series of first preferred shares, certain voting rights effective upon our failing to make payment of six quarterly dividend payments, whether or not consecutive. These voting rights continue for so long as any dividends remain in arrears. These voting rights are the right to one vote for each $25.00 of subscription price on all matters in respect of which shareholders vote, and additionally, the right of all series of first preferred shares, voting as a combined class, to elect two directors of TransAlta if the Board of Directors then consists of less than 16 directors, or three directors if the Board of Directors consists of 16 or more directors. Otherwise, except as required by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Company.

Subject to the share conditions attaching to any particular series providing to the contrary, we may redeem the first preferred shares of a series, in whole or from time to time in part, at the redemption price applicable to each series and we have the right to acquire any of the first preferred shares of one or more series by purchase for cancellation in the open market or by invitation for tenders at a price not to exceed the redemption price applicable to the series.

Series A, B, C, D, E, F and G First Preferred Shares

The holders of Series A, C, E and G first preferred shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, as and when declared by the Board, to be reset periodically on prescribed dates to an annualized rate equal to the sum of the then five-year Government of Canada bond yield, calculated at the start of the applicable five-year period, and a spread as set forth in the table below and have the right to convert their shares into cumulative redeemable Series B, D, F and H first preferred shares, respectively, subject to certain conditions, on such conversion dates as set forth in the table below. The Series A, C, E and G first preferred shares are redeemable by TransAlta in whole or in part on such redemption dates as set forth in the table below, by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon.

The holders of Series B, D, F and H first preferred shares will be entitled to receive quarterly floating rate cumulative preferential cash dividends, as and when declared by the Board, at an annualized rate equal to the sum of the then 90-day Government of Canada treasury bill rate, recalculated quarterly, and a spread as set forth in the table below and have the right to convert their shares into Series A, C, E and G first preferred shares, respectively, subject to certain conditions, on such conversion dates as set forth in the table below. The Series B, D, F and H first preferred shares are redeemable by TransAlta in whole or in part after their respective initial redemption date as set forth in the table below, by the payment of an amount in cash for each share to be redeemed equal to (i) $25.00 in the case of redemptions on such redemption dates as set out in the table below, or (ii) $25.50 in the case of redemptions on any other date, in each case plus all accrued and unpaid dividends thereon.

Series of First Preferred Shares	Initial Redemption/ Conversion Date	Redemption/ Conversion Dates	Spread (%)
Series A	March 31, 2016	March 31, 2021 and every fifth year thereafter	2.03
Series B	-	March 31, 2021 and every fifth year thereafter	2.03
Series C	June 30, 2017	June 30, 2022 and every fifth year thereafter	3.10
Series D	-	June 30, 2022 and every fifth year thereafter	3.10
Series E	Sept. 30, 2017	Sept. 30, 2022 and every fifth year thereafter	3.65
Series F	-	Sept. 30, 2022 and every fifth year thereafter	3.65
Series G	Sept. 30, 2019	Sept. 30, 2024 and every fifth year thereafter	3.80
Series H	-	Sept. 30, 2024 and every fifth year thereafter	3.80

The holders of the Series A, B, C, D, E, F and G first preferred shares are not entitled to any voting rights or to receive notice of or to attend shareholders' meetings unless dividends on such series of first preferred shares are in arrears to the extent of six quarterly dividends, whether or not consecutive. Until all arrears of dividends have been paid, holders of the first preferred shares of such series will be entitled: (i) to receive notice of and to attend all shareholders' meetings at which directors are to be elected (other than separate meetings of holders of another class or series of shares); (ii) to one vote in respect of each first preferred share of such series held on all matters in respect of which shareholders vote; and (iii) to vote, together with all other holders of first preferred shares of any series, as a combined class, to elect two directors of the Company if the Board of Directors then consists of fewer than 16 directors, or three directors if the Board of Directors consists of 16 or more directors. Otherwise, except as required by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Company.

Series I First Preferred Shares

The first preferred shares, Series I (Series I Shares), are issued to an affiliate of Brookfield and have a perpetual term and rank *pari passu* to all existing series of first preferred shares of the Company with respect to dividends and liquidation preferences. The Series I Shares are entitled to a seven per cent cumulative dividend payable quarterly in cash.

Under the Investment Agreement with Brookfield, redemption of the Series I Shares will be satisfied through the Hydro Equity Interest (as defined below), or in some cases cash, based on their redemption price. The redemption price payable is equal to the subscription price paid by Brookfield together with all accrued but unpaid dividends thereon (the Redemption Price). Upon the occurrence of an Optional Redemption, as defined

and described below, or a Cash Acceleration Event, as defined and described below, the Company will pay the Redemption Price in cash (the Cash Redemption Amount).

Except in the case of an Optional Redemption by the Company or a Cash Acceleration Event, as described below, the Series I Shares will be exchangeable into interests (Hydro Equity Interest) in the equity (the Hydro Equity) of TA Alberta Hydro LP (Hydro Assets Owner), a special purpose vehicle formed by the Company. At any time after Dec. 31, 2024, but prior to Dec. 31, 2028, Brookfield will be entitled to exchange all, but not less than all, of the Series I Shares requiring the Company to redeem or exchange all of the Series I Shares held by Brookfield (minus the number of Series I Shares that have been redeemed pursuant to an Optional Redemption) (the Exchange Right).

Prior to any Optional Redemption by the Company, the exercise of the Exchange Right or the occurrence of an Equity Acceleration Event, as defined and described below, will entitle Brookfield to receive that percentage of a Hydro Equity Interest that is equal to the aggregate Redemption Price for all Series I Shares issued to Brookfield divided by the tax-affected equity value of the Hydro Assets Owner, as further described in the Investment Agreement (Equity Redemption Amount). The maximum Hydro Equity Interest issuable to Brookfield upon the exercise of the Exchange Right is 49 per cent of the total Hydro Equity. The balance of the Redemption Price will be paid by the Company in cash.

If, at the time the Exchange Right is exercised, the Equity Redemption Amount is insufficient to permit Brookfield to acquire 49 per cent of the Hydro Equity, Brookfield has a one-time top-up option, exercisable until Dec. 31, 2028, to acquire an additional amount of Hydro Equity. As long as Brookfield holds at least 8.5 per cent of the Company's issued and outstanding common shares, Brookfield may purchase: (a) if the 20-day volume weighted average price (VWAP) of the common shares is not less than $14, up to an additional 10 per cent of Hydro Equity, to a maximum interest of 49 per cent of the Hydro Equity; or (b) if the 20-day VWAP of the common shares is not less than $17, the additional percentage required that would bring Brookfield's ownership level up to but not exceeding 49 per cent of the Hydro Equity. If the Exchange Right is exercised and the Equity Redemption Amount is insufficient to permit Brookfield to acquire at least 25 per cent of the Hydro Equity, Brookfield will have an option to acquire that additional percentage of Hydro Equity that would result in Brookfield having 25 per cent of the Hydro Equity upon payment in cash. If Brookfield exercises its top-up option, the cash amount payable by Brookfield is calculated as the same price as in the case of an exchange for the Hydro Equity Interest; however, in such a case, the price is based on the equity value of the Hydro Assets Owner without any reduction for the tax deficiency value associated with certain tax pools. Exercise of this top-up option triggers a lock-up obligation of Brookfield for a further period of 18 months following its exercise.

At any time after Dec. 31, 2028, the Company may redeem the Series I Shares and the related debentures, in whole or in part, at the Redemption Price (the Optional Redemption) provided that the minimum proceeds to Brookfield for each such redemption (other than the final redemption) may not be less than $100,000,000 and further provided that all Series I Shares and related debentures must be redeemed by the Company within 36 months of the date of the first Optional Redemption.

The Investment Agreement also provides for certain acceleration events. In the event of bankruptcy or a breach of certain material covenants by the Company (each, an Equity Acceleration Event), Brookfield will be entitled to give notice and will be entitled to the Equity Redemption Amount. If the Company does not obtain the requisite regulatory approvals for the exchange of Hydro Equity contemplated by the Exchange Right or the Equity Redemption Amount or a final order is made that enjoins the completion of the Exchange Right (Cash Acceleration Event), then Brookfield will be entitled to the Cash Redemption Amount.

Related-Party Articles Provisions

The articles of the Company contain provisions restricting the ability of the Company to enter into a "Specified Transaction" with a "Major Shareholder." A Specified Transaction requires the approval of a majority of the votes cast by holders of voting shares of the Company, as well as the approval of a majority of the votes cast by holders of such voting shares, excluding any Major Shareholder. A Major Shareholder generally means the beneficial owner of more than 20 per cent of the outstanding voting shares of the Company. The articles contain a broad definition of beneficial ownership, and in particular, a person is considered to beneficially own shares owned by their associates and affiliates, as those terms are defined in the articles. Transactions that are considered to be Specified Transactions include the following: a merger or amalgamation of the Company with a Major Shareholder; the furnishing of financial assistance by the Company to a Major Shareholder; certain sales of assets or provision of services by the Company to a Major Shareholder or vice versa; certain issuances of securities by the Company that increase the proportionate voting interest of a Major Shareholder; a reorganization or recapitalization of the Company that increases the proportionate voting interest of a Major Shareholder; and the creation of a class or series of non-voting shares of the Company that has a residual right to participate in earnings of the Company and assets of the Company upon dissolution or winding up.

Shareholder Rights Plan

The Company implemented a shareholder rights plan (Rights Plan) pursuant to a Shareholder Rights Plan Agreement (Rights Plan Agreement) dated as of Oct. 13, 1992, as amended and restated as of April 28, 2022, between the Company and Computershare Trust Company of Canada. The Rights Plan was last confirmed at our annual and special meeting of shareholders on April 28, 2022, and will expire at the close of business on the date of our 2025 Annual and Special Meeting of Shareholders, unless ratified and extended by a further vote of the shareholders. For further particulars, see the Rights Plan Agreement, as amended and restated. A copy of the Rights Plan Agreement is also available electronically on SEDAR+ under our profile, which can be accessed at **www.sedarplus.ca**, and on the SEC's EDGAR system at **www.sec.gov**. A copy of the Rights Plan Agreement may be obtained by contacting the Corporate Secretary, TransAlta Corporation, TransAlta Place, Suite 1400, 1100 1 St SE, Calgary, Alberta T2G 1B1; telephone: (403) 267-7110; or by email: **corporate_secretary@transalta.com**.

For additional information regarding our Capital Structure, please refer see the "Financial Capital" section of the MD&A, which is incorporated by reference herein.

Exchangeable Securities

On March 22, 2019, we entered into the Investment Agreement, whereby Brookfield invested $750 million in the Company through the purchase of Exchangeable Securities, which are exchangeable into an equity ownership interest of TA Alberta Hydro LP. See the "Capital Structure – First Preferred Shares – Series I First Preferred Shares" section of this AIF for further details.

Investment Agreement

The following description of certain provisions of the Investment Agreement is a summary only; it is not comprehensive and is qualified in its entirety by reference to the full text of the Investment Agreement, a copy of which can be found on SEDAR+ under our profile at **www.sedarplus.ca** and on EDGAR under our profile at **www.sec.gov**.

Under the terms of the Investment Agreement, Brookfield committed to purchase TransAlta common shares on the open market to increase its share ownership in TransAlta to not less than nine per cent by May 1, 2021. As of Dec. 31, 2024, Brookfield, through its affiliates, held, owned or had control over an aggregate of 35,523,345 common shares, representing 11.9 per cent of the issued and outstanding common shares, calculated on an undiluted basis. On January 7, 2025, Brookfield, through its affiliates, sold 8,600,000 common shares reducing its ownership to 26,923,345 common shares, representing approximately nine per cent of the issued and outstanding common shares on an undiluted basis.

The Investment Agreement contemplates that the Exchangeable Securities will be a long-term investment and therefore may not be transferred except by Brookfield to one of its affiliates. Brookfield has agreed to be the

sole representative of all of its permitted transferees for the purpose of the Investment Agreement. So long as Brookfield holds the Exchangeable Securities, it is entitled to nominate two directors for election to the Board.

The Investment Agreement included certain standstill commitments by Brookfield that are extended for so long as Brookfield has nominees on the Board of Directors, including restrictions on Brookfield's ability to solicit proxies from the Company's shareholders or making a shareholder proposal.

In accordance with the terms of the Investment Agreement, TransAlta formed a hydro assets operating committee consisting of two representatives from Brookfield and two representatives from TransAlta to provide advice and recommendations in connection with the operation and value maximization of the Alberta hydro assets. In connection with this, the Company committed to pay Brookfield an annual management fee of $1.5 million for six years commencing on May 1, 2019.

Registration Rights Agreement

The following description of certain provisions of the Registration Rights Agreement entered into between Eagle Hydro II (an affiliate of Brookfield) and the Company on May 1, 2019 (Registration Rights Agreement) is a summary only; it is not comprehensive and is qualified in its entirety by reference to the full text of the Registration Rights Agreement, a copy of which can be found on SEDAR+ under our profile at **www.sedarplus.ca**.

The Registration Rights Agreement provides that Eagle Hydro II and any affiliate of Brookfield that becomes party to the Registration Rights Agreement (each a Holder) may, at any time and from time to time, make a written request (Demand Registration) to the Company to file a Prospectus Supplement with the securities commissions or similar authorities in each of the provinces of Canada in respect of the distribution of all or part of the common shares then held by the Holder (Registrable Securities), subject to certain restrictions set forth in the Registration Rights Agreement. Upon receipt by the Company of a Demand Registration, the Company will promptly file a Prospectus Supplement in order to permit the offer and sale or other disposition or distribution in Canada of all or any portion of the Registrable Securities held, directly or indirectly, by the Holder (a Demand Offering). The Company will not be obligated to effect: (a) more than three Demand Offerings in total during the term of the Registration Rights Agreement; or (b) a Demand Offering if the Registrable Securities have an aggregate market price of less than $50 million.

If at any time the Company proposes to file a prospectus supplement with respect to the distribution of any TransAlta common shares to the public, then the Company will give notice of the proposed distribution to each Holder not less than five business days in advance of the anticipated filing date of the prospectus supplement (or, in the case of a “bought deal” or another public offering that is not expected to include a road show, such notice as is practicable under the circumstances), which notice will offer each Holder the opportunity to qualify for distribution such number of Registrable Securities as such Holder may request. The Company will use commercially reasonable efforts to include in such Prospectus Supplement such Registrable Securities (a Piggy Back Offering), unless the Company’s managing underwriter or underwriters determine, in good faith, that including such Registrable Securities in the distribution would, in their opinion, adversely affect the Company’s distribution or sales price of the securities being offered by the Company.

The Demand Offerings and Piggy Back Offerings are subject to various conditions and limitations. The Company is entitled to defer any Demand Offering in certain circumstances, including during a regular annual and quarterly blackout period in respect of the release of its financial results.

The Registration Rights Agreement includes provisions providing for each of the Company and the Holders to indemnify each other for losses or claims caused by the applicable party’s inclusion of a misrepresentation in disclosure included in any prospectus and for breaches of applicable securities laws.

In the case of a prospectus supplement filed in connection with a Demand Offering or Piggy Back Offering, the Company will pay all applicable fees and expenses incidental to the Company’s performance of, or compliance with, the terms of such offering, provided that in the event any Registrable Securities are freely tradeable at the time the Company receives the offering request, the Company and the Holders will be jointly and severally responsible for the proportionate share of registration fees and expenses of any Holders based on the total offering price of the freely tradeable securities sold by the Holders to the total offering price of all the Securities sold by the Company in such offering. The Company and the Holders will be jointly and severally

responsible for paying all selling expenses (including fees or commissions payable to an underwriter, investment banker, manager or agent and any transfer taxes attributable to the sale of Registrable Securities) with respect to Registrable Securities sold by the Holders and the Company will pay all selling expenses with respect to any Securities sold for the account of the Company. The Company and the Holders will be solely responsible on a joint and several basis for all out-of-pocket expenses incurred by any Holders in connection with a Demand Offering or Piggy Back Offering.

If a Holder ceases to be affiliated with the Company, the Holder will cease to have any rights or obligations under the Registration Rights Agreement. The Registration Rights Agreement will terminate when Brookfield, together with its affiliates, beneficially owns in the aggregate less than three per cent of the issued and outstanding common shares.

Additional details about the Brookfield Investment can be found in our material change report dated March 26, 2019, available electronically on SEDAR+ at **www.sedarplus.ca** and on EDGAR at **www.sec.gov**. Copies of the Investment Agreement, together with copies of the exchangeable debenture and the Registration Rights Agreement are also available on SEDAR+ and on EDGAR. Shareholders are encouraged to read these documents in their entirety.

Credit Ratings

Credit ratings provide information relating to our financing costs, liquidity and operations and affect our ability to obtain short-term and long-term financing and/or the cost of such financing. Our credit ratings as at Dec. 31, 2024, are as follows:

	Morningstar DBRS	Moody's	S&P Global Ratings
Issuer Rating	BBB (low)	Not applicable	BB+
Corporate Family Rating	Not applicable	Ba1	Not applicable
Preferred Shares	Pfd-3 (low)[(1)]	Not applicable	P-4(High)
Unsecured Debt/MTNs	BBB (low)	Ba1/LGD4	BB+
Rating Outlook	Stable	Stable	Stable

(1) The outstanding Preferred Shares all have the same rating.

Morningstar DBRS

Morningstar DBRS' corporate rating analysis begins with evaluation of the fundamental creditworthiness of the issuer and also takes the issuer's business and financial risks into account, which is reflected in an "issuer rating." Issuer ratings address the overall credit strength of the issuer. Unlike ratings on individual securities or classes of securities, issuer ratings are based on the entity itself and do not include consideration for security or ranking. Ratings that apply to actual securities (secured or unsecured) may be higher, lower or equal to the issuer rating for a given entity. As at Dec. 31, 2024, our issuer rating was BBB (low) with a stable outlook. An issuer rating of BBB means the issuer has adequate credit quality, its capacity for the payment of financial obligations is considered acceptable, and it may be vulnerable to future events. Each rating category is denoted by the subcategories "high" and "low." The absence of either a "high" or "low" designation indicates the rating is in the middle of the category. A BBB rating is the fourth highest out of 10 categories.

The Morningstar DBRS preferred share rating scale is used in the Canadian securities market and is meant to give an indication of the risk that a borrower will not fulfil its full obligations in a timely manner, with respect to both dividend and principal commitments. Every Morningstar DBRS rating is based on quantitative and qualitative considerations relevant to the borrowing entity. Each rating category is denoted by the subcategories "high" and "low." The absence of either a "high" or "low" designation indicates the rating is in the middle of the category. Preferred shares rated Pfd-3 are of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adverse conditions present that detract from

debt protection. Each of the Series A, B, C, D, E and G first preferred shares have been rated Pfd-3 (low) (stable). The Pfd-3 rating is the third highest out of six categories.

The Morningstar DBRS long-term rating scale provides an opinion on the risk of default, which is the risk that an issuer will fail to satisfy its financial obligations in accordance with the terms under which an obligation has been issued. Ratings are based on quantitative and qualitative considerations relevant to the issuer, and the relative ranking of claims. All rating categories other than AAA and D also contain subcategories "high" and "low". The absence of either a "high" or "low" designation indicates the rating is in the middle of the category. Debt securities rated BBB are of adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, but may be vulnerable to future events. A BBB rating is the fourth highest out of 10 categories.

Moody's

Moody's Corporate Family Ratings (CFRs) are long-term ratings that reflect the relative likelihood of a default on a corporate family's debt and debt-like obligations and the expected financial loss suffered in the event of default. A CFR is assigned to a corporate family as if it had a single class of debt and a single consolidated legal entity structure. A CFR does not refer to an obligation or class of debt and thus does not reflect priority of claim. As at Dec. 31, 2024, our Corporate Family Rating was Ba1 with a stable outlook. Obligations rated Ba are judged to be speculative and are subject to substantial credit risk. Moody's appends the numerical modifiers 1, 2 and 3 to each generic rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking, and the modifier 3 indicates a ranking in the lower end of that generic rating category. The Ba rating category is the fifth-highest rating out of nine rating categories.

Moody's long-term ratings are assigned to issuers or obligations with an original maturity of 11 months or more and reflect both the likelihood of a default or impairment on contractual financial obligations and the expected financial loss suffered in the event of default or impairment. As at Dec. 31, 2024, our senior unsecured long-term debt is rated Ba1/LGD4. The Ba rating category is the fifth-highest rating out of nine rating categories. Obligations rated Ba are judged to be speculative and are subject to substantial credit risk.

Moody's Loss Given Default (LGD) assessments are point-in-time opinions about expected loss given default expressed as a percentage of principal and accrued interest at the resolution of the default. One of the six LGD assessments is assigned to individual loan, bond and preferred stock issues. The firm-wide or enterprise expected LGD rate generally approximates a weighted average of the expected LGD rates on the firm's liabilities (excluding preferred stock), where the weights equal each obligation's expected share of the total liabilities at default. As at Dec. 31, 2024, our LGD assessment from Moody's was LGD4, which represents a loss range of greater than or equal to 50 per cent and less than 70 per cent. LGD4 is the fourth-highest assessment category out of six categories.

S&P Global Ratings

The S&P Global Ratings issue credit rating is a forward-looking opinion about the creditworthiness of an obligor with respect to a specific financial obligation, a specific class of financial obligations or a specific financial program (including ratings on medium-term note programs and commercial paper programs). It takes into consideration the creditworthiness of guarantors, insurers or other forms of credit enhancement on the obligation and takes into account the currency in which the obligation is denominated. The opinion reflects S&P Global Ratings' view of the obligor's capacity and willingness to meet its financial commitments as they come due, and may assess terms, such as collateral security and subordination, which could affect ultimate payment in the event of default. As at Dec. 31, 2024, our issuer credit rating was BB+ with a stable outlook. This is the fifth highest of 11 ratings categories. An obligor rated BB is less vulnerable in the near-term than other lower-rated obligors. However, it faces major ongoing uncertainties and exposure to adverse business, financial, or economic conditions that could lead to the obligor's inadequate capacity to meet its financial commitments. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

The S&P Global Ratings Canadian preferred share rating scale serves issuers, investors and intermediaries in the Canadian financial markets by expressing preferred share ratings (determined in accordance with global rating criteria) in terms of rating symbols that have been actively used in the Canadian market over a number of years. The S&P Global Ratings preferred share rating on the Canadian scale is a forward-looking opinion about the creditworthiness of an obligor with respect to a specific preferred share obligation issued in the Canadian market, relative to preferred shares issued by other issuers in the Canadian market. There is a direct correspondence between the specific ratings assigned on the Canadian preferred share scale and the various rating levels on the global debt rating scale of S&P Global Ratings. Each of our outstanding Preferred Shares Series has been rated P-4 (High). The P-4 (High) rating is the fourth highest of eight categories. A P-4 (High) rating corresponds to a B+ rating on the global preferred share rating scale. Obligors rated BB, B, CCC, CC and C are regarded as having significant speculative characteristics, of which BB indicates the least degree of speculation and C the highest. While some obligors will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposures to adverse conditions. An obligor rated B is more vulnerable to nonpayment than obligations rated BB, but the obligor currently has the capacity to meet its financial commitments on the obligation. Adverse business, financial or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitments.

We are focused on maintaining a strong financial position and cash flow coverage ratios to support our business. Our available credit facilities, funds from operations and debt financing options provide us with financial flexibility.

Note Regarding Credit Ratings

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. The credit ratings accorded to our outstanding securities by Morningstar DBRS, Moody's and S&P Global Ratings, as applicable, are not recommendations to purchase, hold or sell such securities. There is no assurance that the ratings will remain in effect for any given period or that a rating will not be revised or withdrawn entirely by Morningstar DBRS, Moody's or S&P Global Ratings in the future if, in its judgement, circumstances so warrant.

We have paid fees for rating services to Morningstar DBRS, Moody's and S&P Global Ratings during the last two years. We have also paid fees to S&P Global Ratings, Morningstar DBRS and Kroll Bond Rating Agency for certain other services provided to the Company during the last two years.

Dividends

Dividends on our common shares are paid at the discretion of the Board of Directors. In determining the payment and level of future dividends, the Board of Directors considers our financial performance, results of operations, cash flow and needs, with respect to financing our ongoing operations and growth, balanced against returning capital to shareholders.

Dividends on our first preferred shares are payable quarterly, as and when declared by the Board.

TransAlta has declared and paid the following dividends per share on its outstanding common shares and Series A, B, C, D, E, and G first preferred shares for the past three years:

Year	Quarter	Common	Series A First Preferred	Series B First Preferred	Series C First Preferred	Series D First Preferred	Series E First Preferred	Series G First Preferred
2022	First Quarter	$0.0500	$0.17981	$0.13309	$0.25169	-	$0.32463	$0.31175
	Second Quarter	$0.0500	$0.17981	$0.16505	$0.25169	-	$0.32463	$0.31175
	Third Quarter	$0.0500	$0.17981	$0.22099	$0.36588	$0.28841	$0.32463	$0.31175
	Fourth Quarter	$0.0550	$0.17981	$0.33700	$0.36588	$0.40442	$0.43088	$0.31175
2023	First Quarter	$0.0550	$0.17981	$0.37991	$0.36588	$0.45578	$0.43088	$0.31175
	Second Quarter	$0.0550	$0.17981	$0.41100	$0.36588	$0.47769	$0.43088	$0.31175
	Third Quarter	$0.0550	$0.17981	$0.41545	$0.36588	$0.48287	$0.43088	$0.31175

	Fourth Quarter	$0.0550	$0.17981	$0.45288	$0.36588	$0.52030	$0.43088	$0.31175
2024	**First Quarter**	$0.0600	$0.17981	$0.43958	$0.36588	$0.50609	$0.43088	$0.31175
	Second Quarter	$0.0600	$0.17981	$0.43579	$0.36588	$0.50230	$0.43088	$0.31175
	Third Quarter	$0.0600	$0.17981	$0.43373	$0.36588	$0.50097	$0.43088	$0.31175
	Fourth Quarter	$0.0600	$0.17981	$0.39182	$0.36588	$0.45906	$0.43088	$0.42331
2025	**First Quarter**[1]	$0.0600	$0.17981	$0.33972	$0.36588	$0.40568	$0.43088	$0.42331

(1) Dividends have been declared but not yet paid.

TransAlta also declared an aggregate cash dividend in respect to the issued and outstanding Series I Shares for the period starting from and including Dec. 31, 2023, up to but excluding Dec. 31, 2024. The Series I Shares are entitled to a seven per cent cumulative dividend payable quarterly in cash.

Market for Securities

Common Shares

Our common shares are listed on the Toronto Stock Exchange (TSX) under the symbol "TA" and on the New York Stock Exchange (NYSE) under the symbol "TAC".

Our Series A, B, C, D, E, and G first preferred shares are listed on the TSX under the symbols "TA.PR.D", "TA.PR.E", "TA.PR.F", "TA.PR.G", "TA.PR.H" and "TA.PR.J", respectively.

The following table sets forth the reported high and low trading prices and trading volumes of our common shares as reported by the TSX for the periods indicated:

	Price ($)		
Month	**High**	**Low**	**Volume**
2024			
January	11.17	9.72	15,716,148
February	10.12	9.16	14,010,132
March	9.41	8.44	26,988,640
April	9.34	8.22	23,115,015
May	10.06	9.06	22,130,780
June	10.09	9.41	21,249,930
July	10.47	9.30	20,330,194
August	12.15	10.43	22,689,550
September	14.28	11.65	29,752,508
October	14.75	13.86	22,527,880
November	15.99	12.86	28,263,180
December	20.98	15.54	41,514,720
2025			
January	21.22	14.84	53,921,040

The following table sets forth the reported high and low trading prices and trading volumes of our Series A, B, C, D, E and G first preferred shares as reported by the TSX for the periods indicated:

Year	Quarter	Series A First Preferred	Series B First Preferred	Series C First Preferred	Series D First Preferred	Series E First Preferred	Series G First Preferred
2024							
January	High	13.97	16.23	18.68	20.10	21.99	21.48
	Low	12.18	14.62	17.85	18.40	21.17	19.68
	Volume Traded	111,046	84,044	104,865	6,770	97,836	95,042
February	High	14.30	16.71	18.70	21.00	21.78	21.49
	Low	13.33	15.84	17.91	19.25	21.20	20.61
	Volume Traded	96,122	56,407	126,735	9,308	68,959	51,669
March	High	13.70	15.90	18.99	20.35	21.90	21.61
	Low	13.40	15.50	17.95	19.41	21.00	20.61
	Volume Traded	32,541	23,986	46,169	8,997	72,010	71,542
April	High	13.93	16.00	19.07	22.00	21.95	23.56
	Low	13.46	15.65	18.30	18.66	21.30	21.63
	Volume Traded	369,647	49,916	113,916	11,440	154,380	162,722
May	High	15.50	17.04	19.39	22.50	22.66	24.10
	Low	13.90	15.85	18.40	19.50	21.62	23.15
	Volume Traded	353,680	$77,680.00	411,190	4,428	104,512	167,660
June	High	15.01	16.69	19.25	20.88	22.44	23.67
	Low	13.84	15.82	17.75	19.4	20.55	22.32
	Volume Traded	71,297	37,652	191,729	7,850	94,486	148,295
July	High	15.00	16.50	19.28	20.75	22.64	24.05
	Low	14.31	16.00	18.40	18.00	21.30	22.80
	Volume Traded	100,731	25,222	123,209	12,395	240,777	106,144
August	High	14.90	16.59	20.15	21.50	23.60	24.10
	Low	14.26	15.96	19.00	19.48	22.41	23.02
	Volume Traded	84,054	39,030	82,518	5,050	119,993	168,653
September	High	15.39	17.40	19.99	21.50	23.57	23.70
	Low	14.65	16.01	19.42	19.25	22.75	22.98
	Volume Traded	84,054	96,635	100,089	14,014	86,178	411,005
October	High	15.43	17.50	20.02	21.50	23.72	23.75
	Low	14.75	16.52	19.52	19.51	22.75	23.10
	Volume Traded	189,328	45,150	99,026	9,935	76,280	121,387
November	High	15.29	16.85	20.51	21.99	23.41	23.59
	Low	14.71	16.04	19.55	20.00	22.72	22.95
	Volume Traded	102,870	30,966	110,820	7,720	69,656	68,872
December	High	15.53	16.90	20.72	22.19	23.55	23.82
	Low	14.93	16.01	19.92	19.45	22.72	23.20
	Volume Traded	106,310	54,438	98,402	11,340	85,245	73,067
2025							
January	High	16.06	16.85	21.40	21.65	24.09	24.38
	Low	15.44	16.20	20.58	19.60	23.23	23.55
	Volume Traded	572,628	56,417	130,080	12,815	337,601	98,503

Directors and Officers

The name, province or state and country of residence of each of our directors as at Dec. 31, 2024, their respective position and office and their respective principal occupation during the five preceding years, are set out below. The year in which each director was appointed to serve on the Board of Directors is also set out below. Each director is appointed to serve until the next annual meeting of TransAlta or until his or her successor is elected or appointed.

Name, Province (State) and Country of Residence	Year First Became Director	Principal Occupation
John P. Dielwart Alberta, Canada	2014	Mr. Dielwart is the Chair of the Board of Directors. He was formerly Chief Executive Officer of ARC Resources Ltd., overseeing the growth of the company from a startup in 1996 to a company with a total capitalization of approximately $10 billion at the time of his retirement in 2013. After his retirement from ARC Resources, Mr. Dielwart re-joined ARC Financial Corp. as Vice-Chair and Partner. In 2020, Mr. Dielwart resigned from the Board of ARC Financial but remained as Partner and a member of ARC Financial's Investment Committee. He is currently representing ARC Financial on the board of Aspenleaf Energy Limited. He is a past-Chair of the Board of Governors of the Canadian Association of Petroleum Producers and a member of the Association of Professional Engineers and Geoscientists of Alberta.
Alan J. Fohrer California, United States	2013	Mr. Fohrer is the former Chair and Chief Executive Officer of Southern California Edison Company, a subsidiary of Edison International (Edison) that is one of the largest electric utilities in the United States. Mr. Fohrer served as President and Chief Executive Officer of Edison Mission Energy (EME) from 2000 to 2001, a former subsidiary of Edison that owned and operated independent power facilities. During his tenure at EME, Mr. Fohrer restructured a number of international projects, which enhanced the value of the assets sold in subsequent years. Mr. Fohrer also served as Vice-President, Senior Vice-President, Executive Vice-President and Chief Financial Officer of both Edison and Southern California Edison from 1991 to 2000. After 37 years with Edison, Mr. Fohrer retired in December 2010. Mr. Fohrer is currently an independent member of the board of TXNM Energy, Inc. (previously PNM Resources, Inc.), a publicly traded energy holding company. He is also a member of the Viterbi School of Engineering Board of Councilors for the University of Southern California and on the Board of the California Science Center Foundation. Mr. Fohrer has served on boards of directors of the Institute of Nuclear Power Operations, the California Chamber of Commerce, Duratek, Inc., Osmose Utilities Services, Inc., MWH, Inc., Blue Shield of California and Synagro.

Name, Province (State) and Country of Residence	Year First Became Director	Principal Occupation
Laura W. Folse Texas, United States	2021	Ms. Folse was the Chief Executive Officer of BP Wind Energy North America Inc. As Chief Executive Officer for BP Wind Energy she led a business with over 500 employees and contractors that consisted of 14 wind energy generation plants across eight states with an operating capacity of over 2.5 gigawatts. Prior to her role as Chief Executive Officer of BP Wind Energy, she served at BP p.l.c. as Executive Vice President, Science, Technology, Environment and Regulatory Affairs, in which she led the operational, scientific and technological programs within the multi-billion dollar cleanup and restoration effort in response to the 2010 BP Macondo well explosion off the coast of Louisiana. At its peak, the cleanup project team that she led consisted of over 45,000 people working across the U.S. Gulf and Mexico. She successfully negotiated with federal, state and local government officials to implement and conclude the offshore and onshore cleanup efforts. Prior thereto, she held numerous leadership roles with increasing responsibility and complexity within BP p.l.c. Ms. Folse is an independent member of the Board of Directors of Pacolet Milliken, a private investment company operating in real estate and power and infrastructure. Ms. Folse was a board member for the American Wind Energy Association from 2016 to 2019.
Harry A. Goldgut Ontario, Canada	2019	Mr. Goldgut is Vice Chair of Brookfield's Infrastructure and Renewable Power and Transition groups and provides strategic advice related to Brookfield's open-ended Infrastructure Fund. He is also one of two Brookfield nominees to the Board. Mr. Goldgut was the Chief Executive Officer or Co-CEO and Chair of Brookfield Renewable Power Inc. from 2000 to 2008, and thereafter, until 2015, he was Chair of Brookfield's Power and Utilities Group. From 2015 to 2018, he served as Executive Chair of Brookfield's Infrastructure and Renewable Power groups. He joined Brookfield in 1997 and led the expansion of Brookfield's renewable power and utilities operations. He had primary responsibility for strategic initiatives, acquisitions and senior regulatory relationships. He was responsible for the acquisition of the majority of Brookfield's renewable power assets. He also played a role in the restructuring of the electricity industry in Ontario as a member of several governmental committees, including the Electricity Market Design Committee, the Minister of Energy's Advisory Committee, the Clean Energy Task Force, the Ontario Energy Board Chair's Advisory Roundtable and the Ontario Independent Electricity Operator CEO Roundtable on Market Renewal. Mr. Goldgut also serves on the board of directors of Isagen S.A. ESP, the third-largest power generation company in Colombia, and the Princess Margaret Cancer Foundation in Toronto.

Name, Province (State) and Country of Residence	Year First Became Director	Principal Occupation
John H. Kousinioris Alberta, Canada	2021	Mr. Kousinioris is President and Chief Executive Officer of TransAlta. Prior to his appointment as President and CEO in 2021, Mr. Kousinioris served as Chief Operating Officer of the Company. As Chief Operating Officer, he was responsible for overseeing operations, shared services, commercial, trading, customer solutions, hedging and optimization at the Company. Prior thereto, Mr. Kousinioris was TransAlta's Chief Growth Officer and Chief Legal and Compliance Officer. Mr. Kousinioris' prior leadership roles have provided him with responsibility for almost every aspect of the Company's business. He was also the President of TransAlta Renewables Inc. until Feb. 5, 2021. Prior to joining TransAlta, Mr. Kousinioris was a partner and co-head of the corporate commercial department at Bennett Jones LLP with 30 years of experience in securities law, mergers and acquisitions, and corporate governance matters. He is also Chair of the Board of Governors of Bow Valley College and a member of the Board of Directors of the Calgary Stampede Foundation.
Candace J. MacGibbon Ontario, Canada	2023	Ms. MacGibbon is the former Chief Executive Officer and Director of INV Metals Inc., a TSX-listed mining company, from 2015 to 2021, where she was responsible for determining and implementing corporate strategy. Prior thereto, Ms. MacGibbon was the former President and Chief Financial Officer of INV Metals Inc. from 2008 to 2015, responsible for financial and regulatory reporting and for the company's treasury, financial strength and investment policy. Ms. MacGibbon previously held roles within global mining institutional equity sales with RBC Capital Markets and in base metals research as an equity research associate with BMO Capital Markets. Ms. MacGibbon was a former manager at Deloitte LLP and cost analyst with Inco Limited. She is also a board member of Osisko Gold Royalties and a member of Osisko Gold Royalties Audit and Human Resources Committees. Ms. MacGibbon is the president-elect of the Canadian Institute of Mining, Petroleum and Metallurgy. She is a Chartered Professional Accountant with over 25 years' experience in the mining sector and capital markets.

Name, Province (State) and Country of Residence	Year First Became Director	Principal Occupation
Thomas M. O'Flynn New Jersey, United States	2021	Mr. O'Flynn was the Chief Executive Officer and Chief Investment Officer, AES Infrastructure Advisors. Prior thereto, until 2019, he was Executive Vice President and Chief Financial Officer, Head of U.S. Renewables at AES Corporation and responsible for all aspects of global finance and merger and acquisition (M&A) teams across six global regions. During his tenure, Mr. O'Flynn helped lead AES through a significant transformation, including strategic exits of non-core markets, which resulted in improved financial stability and allowed for the redeployment of cash to primary growth markets. AES's total shareholder return increased 54 per cent during his tenure and its credit rating improved significantly. Mr. O'Flynn was also a key driver in initiating a major transition to renewables and green energy to significantly improve AES's growth profile and reduce its carbon footprint. Mr. O'Flynn is the Lead Operating Director of Dimension Renewable Energy, a community solar company. He is an Operating Director of Exus Management Partners, a renewables management and development company. Mr. O'Flynn is a director of Nexus Water Group, a water utility company. Mr. O'Flynn is a Senior Advisor with Energy Impact Partners, a private energy technology fund investing in high-growth companies in the energy, utility and transportation industries. Mr. O'Flynn was Chief Financial Officer of Powin Energy from December 2021 until December 2022, a battery energy storage company in which Energy Impact Partners is a significant investor. Mr. O'Flynn was with The Blackstone Group Inc. where he was Senior Advisor, Power and Utility Sector, and Chief Operating Officer and Chief Financial Officer of Transmission Developers Inc., a Blackstone-controlled entity that develops innovative power transmission projects in an environmentally responsible manner. Prior thereto he was Executive Vice President and Chief Financial Officer at Public Service Enterprise Group Incorporated and was Head of North American Power at Morgan Stanley.
Bryan D. Pinney Alberta, Canada	2018	Mr. Pinney has over 30 years of experience serving many of Canada's largest corporations, primarily in energy and resources and construction. Mr. Pinney served as Calgary Managing Partner of Deloitte LLP from 2002 through 2007 and as National Managing Partner of Audit & Assurance from 2007 to 2011 and Vice-Chair until June 2015. Mr. Pinney was a past member of Deloitte LLP's Board of Directors. He was a partner at Andersen LLP and served as Calgary Managing Partner from 1991 through May 2002. Mr. Pinney is currently the lead director for North American Construction Group Ltd. (NYSE, TSX) and a director of SNDL Inc. (NASDAQ). Mr. Pinney is the former chair of the Board of Governors of Mount Royal University and has served on a number of non-profit boards. He is a Fellow of the Institute of Chartered Accountants and a Chartered Business Valuator, and he holds the ICD.D designation granted by the Institute of Corporate Directors.

Name, Province (State) and Country of Residence	Year First Became Director	Principal Occupation
James Reid Alberta, Canada	2021	Mr. Reid is a former Managing Partner of Brookfield Asset Management Inc. who led Brookfield's Private Equity Group in Calgary, Alberta. In that role he was responsible for originating, evaluating and structuring investments and financings in the energy sector and overseeing operations in Brookfield's private equity energy segment. Prior to moving into the private equity group, Mr. Reid was the Chief Investment Officer, Energy for Brookfield's Infrastructure Group. He established Brookfield's Calgary office in 2003 after spending several years as Chief Financial Officer for two oil and gas exploration and production companies in Western Canada. Mr. Reid is also one of two Brookfield nominees to the Board pursuant to the Investment Agreement. Mr. Reid obtained his Chartered Accountant designation at PricewaterhouseCoopers in Toronto.
Manjit K. Sharma Ontario, Canada	2023	Ms. Sharma has over 30 years of experience that spans a variety of industries (power generation, oil and gas, financial services, manufacturing, engineering services and others). From 2020 to 2021, she was the Chief Financial Officer of WSP Canada Inc. In this role, she was responsible for leading the finance, real estate, procurement, tax and shared services functions on an interim contract. She was the Chief Financial Officer of GE Canada from 2016 to 2019. From 1999 to 2016, she held various senior positions with GE Canada, with responsibilities that spanned business strategy development and execution, business product and services development, mergers and acquisitions, tax oversight, risk, governance, key components of human resources strategy (including compensation, union negotiations, pension and benefits), and diversity and inclusion. Ms. Sharma currently serves as a board member of each of Vermilion Energy Inc., Finning International Inc. and Export Development Canada. Ms. Sharma is a Fellow Chartered Accountant and holds the ICD.D Directors designation and the GCB.D Global Competent Boards designation.

Name, Province (State) and Country of Residence	Year First Became Director	Principal Occupation
Sandra R. Sharman Ontario, Canada	2020	Ms. Sharman is the Senior Vice President and Group Head, People, Culture and Brand of Canadian Imperial Bank of Commerce (CIBC) (chartered bank). In this role, she leads the Human Resources, Communications, Marketing and Enterprise Real Estate teams at CIBC, supporting execution of business strategy, transforming to a purpose-driven bank and enabling a world-class culture. Ms. Sharman and her team are responsible for developing and delivering the Global Human Capital Strategy designed to challenge conventional thinking, drive business solutions and shape the culture of the bank. Ms. Sharman is a proven business leader with over 30 years of human resources and financial services experience in both Canada and the United States, and she has played a leading role in shaping an inclusive and collaborative culture at CIBC, focused on empowering and enabling employees to reach their full potential. Ms. Sharman assumed the leadership of Human Resources at CIBC in 2014 and added accountability for communications and public affairs in 2017. Since then, her portfolio has expanded to encompass purpose, brand, marketing and, most recently, corporate real estate.
Sarah A. Slusser Washington, United States	2021	Ms. Slusser is the Chief Executive Officer of Cypress Creek Renewables, LLC (Cypress Creek), a solar and storage independent power producer that develops, owns and operates projects in the United States. She joined Cypress Creek as Chief Executive Officer in 2019 to reposition the company for sustainable growth. Prior to this, she founded Point Reyes Energy Partners LLC, a solar and energy storage advisory and development company, where she provided strategic advice to a number of large companies in the renewable sector. She remains a founding partner of Point Reyes Energy Partners. Prior to this, she co-founded GeoGlobal Energy LLC, a geothermal company in the United States, Chile and Germany, which was sold to its cornerstone investor in 2015. Before co-founding GeoGlobal Energy, Ms. Slusser worked at AES for 21 years, where she advanced into increasingly significant leadership roles, ultimately being appointed Senior Vice President and Managing Director reporting directly to the Chief Executive Officer and leading the corporate M&A group. She was President of one of eight divisions of AES that was responsible for all development, construction and operations in the Caribbean, Mexico and Central America. Ms. Slusser is a member of the Board of Directors of the Redwood Foundation, a family foundation promoting education and the environment and Our Food Chain, a non-profit promoting healthy eating.

Officers

The name, province or state and country of residence of each of our executive officers as at Feb. 19, 2025, their respective position and office and their respective principal occupation are set out below.

Name	Principal Occupation	Residence
John H. Kousinioris	President and Chief Executive Officer	Alberta, Canada
Joel E. Hunter	Executive Vice President, Finance and Chief Financial Officer	Alberta, Canada
Jane N. Fedoretz	Executive Vice President, People, Culture and Chief Administrative Officer	Alberta, Canada
Kerry L. O'Reilly Wilks	Executive Vice President, Growth and Energy Marketing	Alberta, Canada
Christopher D. Fralick	Executive Vice President, Generation	Alberta, Canada
Mark A. Flickinger	Executive Vice President, Project Delivery and Construction	Idaho, United States
Blain M. van Melle	Executive Vice President, Commercial and Customer Relations	Alberta, Canada
Nancy L. Brennan	Executive Vice President, Legal and External Affairs	Alberta, Canada
David C. Little	Senior Vice President, Growth	California, United States

All the executive officers of TransAlta have held their present principal occupation or position for the past five years, except for the following:

- Prior to April 2021, Mr. Kousinioris was Chief Operating Officer of TransAlta.
- Prior to July 2024, Mr. Hunter was Executive Vice-President and Chief Financial Officer at TC Energy Corporation. Prior to August 2021, Mr. Hunter was Senior Vice-President, Capital Markets at TC Energy Corporation.
- Prior to November 2023, Ms. Fedoretz was Executive Vice President, People, Talent and Transformation of TransAlta. Prior to February 2021, Ms. Fedoretz was Chief Talent and Transformation Officer of TransAlta.
- Prior to November 2023, Ms. O'Reilly Wilks was Executive Vice President, Legal, Commercial and External Affairs of TransAlta. Prior to February 2021, Ms. O'Reilly Wilks was Chief Officer, Legal, Regulatory and External Affairs of TransAlta.
- Prior to September 2022, Mr. Fralick was President and Chief Executive Officer of Atura Power, a Canadian power generation company. Prior to 2020, Mr. Fralick was Chief Operating Officer of Ontario Power Generation.
- Prior to July 2024, Mr. Flickinger was Vice President of Engineering and Construction of Pattern Energy Group LP.
- Prior to November 2023, Mr. van Melle was Executive Vice President, Alberta Business of TransAlta. Prior to February 2021, Mr. van Melle was Senior Vice President, Trading and Commercial of TransAlta.
- Prior to December 2024, Ms. Brennan was Executive Vice President, Legal, External Affairs and Corporate Secretary. Prior to July 2024, Ms. Brennan was Executive Vice President, Legal of TransAlta. Prior to February 2024, Ms. Brennan was Senior Vice President, Sustainability, External Relations and General Counsel of Keyera Corp.
- Prior to November 2023, Mr. Little was Vice President and Managing Director - USA of Innergex Renewable Energy Inc. Prior to July 2021, Mr. Little was Senior Director and Head of USA of Innergex Renewable Energy Inc.

As of Feb. 19, 2025, the directors and executive officers of TransAlta, as a group, beneficially owned, directly or indirectly, or exercised control or direction over less than one per cent of our outstanding common shares.

Interests of Management and Others in Material Transactions

No director or executive officer of TransAlta, no person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over more than 10 per cent of our common shares, and no associate or affiliate of any of them, has or has had any material interest, direct or indirect, in any transaction involving TransAlta within the three most recently completed financial years or to date in 2025 or in any proposed transactions that have materially affected or will materially affect TransAlta.

In connection with the Brookfield Investment, Mr. James Reid and Mr. Harry Goldgut were initially nominated by Brookfield and elected to the Board of Directors on May 4, 2021, and April 26, 2019, respectively. See the "Directors and Officers" section of this AIF for further details. Brookfield is also entitled to receive certain funding fees, management fees and interest and dividends on its $750 million investment.

Indebtedness of Directors, Executive Officers and Senior Officers

Since Jan. 1, 2024, there has been no indebtedness outstanding to TransAlta from any of our directors, executive officers, senior officers or associates of any such directors, executive officers or senior officers.

Corporate Cease Trade Orders, Bankruptcies or Sanctions

Corporate Cease Trade Orders and Bankruptcies

Except as noted below, no director, executive officer or controlling security holder of the Company is, as at the date of this AIF, or has been, within the past 10 years before the date hereof, a director or executive officer of any other issuer that, while that person was acting in that capacity:

- Was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; or
- Was subject to an event that resulted, after the person ceased to be a director or executive officer, in the company being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; or
- Within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Mr. Reid is a director of Second Wave Petroleum Inc. (SWP), a private oil and gas exploration and production company. On June 30, 2017, SWP made an assignment into bankruptcy pursuant to the *Bankruptcy and Insolvency Act* (Canada) (BIA). On Sept. 7, 2017, SWP made a proposal under the BIA and on Oct. 5, 2017, the proposal was approved by the Court of Queen's Bench of Alberta and the bankruptcy was annulled.

Mr. Dielwart was chair of the board of directors of Denbury Resources Inc. (Denbury), which filed for bankruptcy protection in the United States on July 29, 2020, under a prepackaged reorganization plan with its bondholders. Denbury emerged from Chapter 11 on Sept. 18, 2020, at which time the board of directors was reconstituted and Mr. Dielwart ceased being a director.

Personal Bankruptcies

No director, executive officer or controlling security holder of the Company has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or

became subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold such person's assets.

Penalties or Sanctions

No director, executive officer or controlling security holder of the Company has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, other than penalties for late filing of insider reports; or been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Material Contracts

Other than contracts entered into in the ordinary course of business, the Company believes that the following are material contracts, the particulars of which are disclosed elsewhere in this AIF, to which the Company or its subsidiaries are a party:

- Investment Agreement – See the "Capital Structure – Exchangeable Securities – Investment Agreement" section of this AIF for further details.
- Registration Rights Agreement – See the "Capital Structure – Exchangeable Securities – Registration Rights Agreement" section of this AIF for further details.
- Off-Coal Agreement – See the "Business of TransAlta – Gas Segment – Off-Coal Agreement" section of this AIF for further details.

Conflicts of Interest

Circumstances may arise where members of the Board of Directors serve as directors or officers of corporations that are in competition with the interests of TransAlta. No assurances can be given that opportunities identified by such members of the Board of Directors will be provided to us. However, our policies provide that each director and executive officer must comply with the disclosure requirements of the CBCA regarding any material interest. If a declaration of material interest is made, the declaring director shall not vote on the matter if put to a vote of the Board of Directors. In addition, the declaring director may be requested to recuse himself or herself from the meeting when such matter is being discussed.

Legal Proceedings and Regulatory Actions

TransAlta is occasionally named as a party in claims and legal proceedings that arise during the normal course of its business. We review each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in our favour or that such claim may not have a material adverse effect on TransAlta.

Brazeau Facility — Well Licence Applications to Consider Hydraulic Fracturing

The Alberta Energy Regulator (AER) issued a subsurface order on May 27, 2019, which does not permit any hydraulic fracturing within three kilometres of the Brazeau facility, but permits hydraulic fracturing in all formations (except the Duvernay) within three to five kilometres of the Brazeau facility. Subsequently, two oil and gas operators submitted applications to the AER for 10 well licences (which include hydraulic fracturing activities) within three to five kilometres of the Brazeau facility.

The Company's position, based on independent expert analysis commissioned by the Government of Alberta, is that hydraulic fracturing activities within five kilometres of the Brazeau facility pose an unacceptable risk and that the applications should be denied. The regulatory hearing to consider these applications - Proceeding 379 - has been adjourned to November 2025.

Brazeau Facility — Claim against the Government of Alberta

On Sept. 9, 2022, the Company filed a Statement of Claim against the Government of Alberta in the Alberta Court of King's Bench seeking a declaration that: (a) granting mineral leases within five kilometres of the Brazeau facility is a breach of a 1960 agreement between the Company and the Alberta Government; and (b) the Government of Alberta is required to indemnify the Company for any costs or damages that result from the risks of hydraulic fracturing near the Brazeau facility. On Sept. 29, 2022, the Government of Alberta filed its Statement of Defence, which asserts, among other things, that the Company: (a) is trying to usurp the jurisdiction of the AER; and (b) is out of time under the *Limitations Act (Alberta)*. The trial is scheduled to be heard in September or October 2025 in the event the parties are unable to resolve the dispute prior to such date.

Brazeau — Spinning Reserve Self-Report

On Nov. 30, 2022, TransAlta self-reported to the Market Surveillance Administrator (MSA) a potential violation of the Independent System Operator rules relating to offers of active spinning reserves at Brazeau when it was not properly configured to do so between Aug. 13, 2021, and Nov. 1, 2022. In 2022 a provision of $20 million was initially recognized in revenue reflecting a potential disgorgement of revenue and $2 million for potential penalties and fines. On Nov. 29, 2024, the MSA issued penalties to TransAlta for this self-report and TransAlta made a payment of $33 million in January 2025.

Transfer Agent and Registrar

The transfer agent and registrar for our common shares and Series A, B, C, D, E and G first preferred shares is Odyssey Trust Company. Common shares are transferable in Vancouver, Calgary and Toronto. Series A, B, C, D, E and G first preferred shares are transferable in Calgary and Toronto. The transfer agent and registrar for our common shares in the United States is Odyssey Transfer and Trust Company at its principal office in Woodbury, Minnesota.

Interests of Experts

The Company's auditors are Ernst & Young LLP, Chartered Professional Accountants, located at 2200, 215 – 2nd Street, S.W., Calgary, Alberta, T2P 1M4.

Our auditors, Ernst & Young LLP is the Company's independent public accountant in the context of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta and the rules and regulations adopted by the United States Securities and Exchange Commission and the Public Company Accounting Oversight Board (United States).

Additional Information

Additional information in relation to TransAlta may be found on our website at **www.transalta.com** and under TransAlta's profile on SEDAR+ at **www.sedarplus.ca** and EDGAR at **www.sec.gov**.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities authorized for issuance under equity compensation plans (all where applicable) is contained in our Management Proxy Circular for the most recent annual meeting of shareholders that involved the election of directors and can be obtained upon request from our Investor Relations department, or as filed on SEDAR+ at **www.sedarplus.ca** and EDGAR at **www.sec.gov**.

Additional financial information is provided in our audited consolidated financial statements as at and for the year ended Dec. 31, 2024, and in the related MD&A.

Audit, Finance and Risk Committee

General

The members of TransAlta's Audit, Finance and Risk Committee (AFRC) satisfy the requirements for independence under the provisions of the Canadian Securities Administrators, National Instrument 52-110 – Audit Committees, Section 303A of the NYSE Rules and Rule 10A-3 under the U.S. *Securities and Exchange Act of 1934*. The AFRC's Charter requires that it be made up of a minimum of three independent directors. The AFRC currently consists of five independent members: Thomas M. O'Flynn (Chair), Alan J. Fohrer, Candace J. MacGibbon, Bryan D. Pinney and Manjit K. Sharma.

All members of the committee are financially literate pursuant to both Canadian and U.S. securities requirements and each member of the AFRC has also been determined by the Board of Directors to be an "audit committee financial expert," within the meaning of Section 407 of the U.S. *Sarbanes-Oxley Act of 2002*.

Audit, Finance and Risk Committee Charter

The Charter of the AFRC is attached as Appendix "A".

Relevant Education and Experience of Audit, Finance and Risk Committee Members

The following is a brief summary of the education or experience of each member of the AFRC that is relevant to the performance of his or her responsibilities as a member of the AFRC, including any education or experience that has provided the member with an understanding of the accounting principles that we use to prepare our annual and interim financial statements.

Name of AFRC Member	Relevant Education and Experience
Thomas M. O'Flynn (Chair)	Mr. O'Flynn was the Chief Financial Officer of Powin Energy, an entity in which Energy Impact Partners LP (a private energy technology fund) is a major investor. Prior thereto, Mr. O'Flynn was Chief Executive Officer and Chief Investment Officer at the AES Infrastructure Advisors, Executive Vice President and Chief Financial Officer at Public Service Enterprise Group Incorporated and Head of North American Power at Morgan Stanley. Mr. O'Flynn has a Bachelor of Arts in economics from Northwestern University and a Master of Business Administration, Finance from the University of Chicago.
Alan J. Fohrer	Prior to his retirement in December 2010, Mr. Fohrer was Chair and Chief Executive Officer of Southern California Edison Company, a subsidiary of Edison and one of the largest electric utilities in the United States. Prior to that, Mr. Fohrer served as Vice-President, Senior Vice-President, Executive Vice-President and Chief Financial Officer of both Edison and Southern California Edison Company. Mr. Fohrer also serves on the audit committee of TXNM Energy, Inc., a public company. Mr. Fohrer holds a Master of Business Administration from California State University in Los Angeles.
Candace J. MacGibbon	Ms. MacGibbon was the former Chief Executive Officer and Chief Financial Officer of INV Metals Inc. Prior to this, she was a former manager at Deloitte LLP and held roles within RBC Capital Markets and BMO Capital Markets. Ms. MacGibbon currently serves as a board member of Osisko Gold Royalties, and she is a member of the Audit of Human Resources Committees of Osisko Gold Royalties. Ms. MacGibbon holds a Bachelor of Arts degree in economics from the University of Western Ontario and is a Chartered Professional Accountant with over 25 years of experience in the mining sector and capital markets.
Bryan D. Pinney	Mr. Pinney has 40 years of experience in financial auditing, valuation and advising companies in energy and natural resources. He is an independent director of North American Construction Group Ltd. and chair of its Audit and Finance Committee. He is also an independent director of SNDL, Inc. and chair of its Audit and Finance Committee. He served as a member of Deloitte's Board of Directors and chair of the Finance and Audit Committee. He was the recent Chair and a member of the Board of Governors of Mount Royal University and has previously served on a number of non-profit boards. He has been a Chartered Accountant since December 1978, a Fellow of the Chartered Professional Accountants of Alberta since January 2009 and a Chartered Business Valuator of Canada since December 1990. Mr. Pinney obtained a Bachelor of Arts in business administration from the University of Western Ontario in 1975 and also completed the Directors Education Program offered by the Institute of Corporate Directors in Canada in 2012.
Manjit K. Sharma	Ms. Sharma was the Chief Financial Officer of WSP Canada Inc. Prior to WSP Canada Inc., she was on the National Executive Team of General Electric Canada (GE Canada), serving as Chief Financial Officer from 2016 to 2019. Ms. Sharma currently serves as a board member of each of Vermilion Energy Inc., Finning International Inc. and Export Development Canada. Ms. Sharma holds a Bachelor of Commerce degree (with honours) from the University of Toronto, is a Fellow Chartered Accountant and holds the ICD.D Directors designation and the GCB.D Global Competent Boards designation.

Other Board Committees

In addition to the AFRC, TransAlta has three other standing committees: the Governance, Safety and Sustainability Committee, the Human Resources Committee and the Investment Performance Committee. The members of these committees as at Dec. 31, 2024, are:

Governance, Safety and Sustainability Committee

Chair: Bryan D. Pinney

Alan J. Fohrer

Laura W. Folse

Sandra R. Sharman

Human Resources Committee

Chair: Sandra R. Sharman

Candace J. MacGibbon

Manjit K. Sharma

Sarah A. Slusser

Investment Performance Committee

Chair: Laura W. Folse

Thomas M. O'Flynn

Harry A. Goldgut

James Reid

Sarah A. Slusser

Mr. John P. Dielwart also attends each of the Committee meetings in his capacity as Chair of the Board of Directors.

Charters of the Governance, Safety and Sustainability Committee, the Human Resources Committee and the Investment Performance Committee may be found on our website under Governance, Board Committees at **www.transalta.com**. Further information about the Board of Directors and our corporate governance may also be found on our website or in our Management Proxy Circular, which is filed on SEDAR+ at **www.sedarplus.ca** and EDGAR at **www.sec.gov**.

Fees Paid to Ernst & Young LLP

For the years ended Dec. 31, 2024, and Dec. 31, 2023, Ernst & Young LLP and its affiliates billed $4,407,734 and $4,788,655, respectively, as detailed below.

Ernst & Young LLP

Year Ended Dec. 31	2024	2023
Audit fees	$ 3,653,823	$ 4,075,612
Audit-related fees	347,345	668,168
Tax fees	356,391	5,850
All other fees	50,175	39,025
Total	**$ 4,407,734**	**$ 4,788,655**

The nature of each category of fees is described below:

Audit Fees

Audit fees are for professional services rendered for the audit and review of our financial statements or services provided in connection with statutory and regulatory filings and providing comfort letters associated with securities documents and statutory audits.

Audit-Related Fees

Assurance and related services that are reasonably related to the performance of the audit or review of our financial statements that are not included in the audit fees. Audit-related fees include pension audits and other compliance audits.

Tax Fees

Tax fees are tax-related services for the review of tax returns, assistance with questions on tax audits and tax planning.

All Other Fees

Products and services provided by the Company's auditor other than those services reported under audit fees, audit-related fees and tax fees. This includes fees related to training services and advice and assistance with ESG services provided by the auditor.

Pre-Approval Policies and Procedures

The AFRC has considered whether the provision of services other than audit services is compatible with maintaining the auditors' independence. In May 2002, the AFRC adopted a policy that prohibits TransAlta from engaging the auditors for "prohibited" categories of non-audit services and requires pre-approval of the AFRC for other permissible categories of non-audit services, such categories being determined under the *Sarbanes Oxley Act of 2002*. This policy also provides that the Chair of the AFRC may approve permissible non-audit services during the quarter and report such approval to the AFRC at its next regularly scheduled meeting.

Appendix "A"

TransAlta Corporation (the “Corporation”)

Audit, Finance and Risk Committee Charter

A. Establishment of Committee and Procedures

1. Composition of Committee

The Audit, Finance and Risk Committee (the "Committee") of the board of directors (the "Board") of TransAlta Corporation (the "Corporation") shall consist of not less than three directors. All members of the Committee shall be determined by the Board to be independent as required under the provisions of Canadian Securities Regulators' Multilateral Instrument 52-110 Audit Committees, Section 303A of the New York Stock Exchange rules and Rule 10A-3 of the U.S. *Securities and Exchange Act of 1934*, as such rules apply to audit committee members. All members of the Committee must be financially literate pursuant to both Canadian and US securities requirements and at least one member must be determined by the Board to be an "audit committee financial expert" within the meaning of Section 407 of the United States *Sarbanes-Oxley Act of 2002* ("Sarbanes-Oxley Act"). Determinations as to whether a particular director satisfies the requirements for membership on the Committee shall be made by the Board at the recommendation of the Governance, Safety and Sustainability Committee (the "GSSC") of the Board.

2. Appointment of Committee Members

Members of the Committee shall be appointed from time to time by the Board, on the recommendation of the GSSC, and shall hold office until the next annual meeting of shareholders, or until their successors are earlier appointed, or until they cease to be directors of the Corporation.

3. Vacancies

Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board and on the recommendation of the GSSC. The Board shall fill any vacancy if the membership of the Committee is less than three directors.

4. Committee Chair

The Board shall appoint a Chair for the Committee on the recommendation of the GSSC.

5. Absence of Committee Chair

If the Chair of the Committee is not present at any meeting of the Committee, one of the members of the Committee who is present at the meeting shall be chosen by the Committee to preside at the meeting.

6. Secretary of Committee

The Committee shall appoint a Secretary who need not be a director of the Corporation.

7. Meetings

The Chair of the Committee may call a regular meeting of the Committee. The Committee shall meet at least quarterly and at such other times each year as it deems appropriate to fulfill its responsibilities. In addition, the Chair of the Committee or any two members may call a special meeting of the Committee at any time.

The Committee shall also meet in separate executive sessions.

8. Quorum

A majority of the members of the Committee, present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak to each other, shall constitute a quorum.

9. Notice of Meetings

Notice of the time and place of every meeting shall be given in writing (including by way of written facsimile communication or email) to each member of the Committee at least 48 hours prior to the time fixed for such meeting, provided, however, that a member may in any manner waive notice of a meeting; and attendance of a member at a meeting constitutes a waiver of notice of the meeting, except where a member attends for the express purpose of objecting to the transaction of any business on the ground that the meeting is not lawfully called. Notice of every meeting shall also be provided to the external and internal auditors.

10. Attendance at Meetings

At the invitation of the Chair of the Committee, other Board members, the President and Chief Executive Officer ("CEO") of the Corporation, other officers or employees of the Corporation, the external auditors, and other experts or consultants may attend a meeting of the Committee.

11. Procedure, Records and Reporting

Subject to any statute or the articles and by-laws of the Corporation, the Committee shall fix its own procedures at meetings, keep records of its proceedings and report to the Board generally not later than the next scheduled meeting of the Board.

12. Review of Charter and Evaluation of Committee

The Committee shall evaluate its performance and review and assess the adequacy of its Charter at least annually or otherwise, as it deems appropriate. All changes proposed by the Committee are reviewed and approved by the GSSC and the Board.

13. Outside Experts and Advisors

In consultation with the Board, the Committee Chair, on behalf of the Committee or any of its members, is authorized, at the expense of the Corporation, when deemed necessary or desirable, to retain independent counsel, outside experts and other advisors to advise the Committee independently on any matter. The retention of such counsel, expert or advisor in no way requires the Committee to act in accordance with the recommendations of such counsel, expert or advisor.

B. Duties and Responsibilities of the Chair

The fundamental responsibility of the Chair of the Committee is to effectively manage the duties of the Committee.

The Chair is responsible for:

1. Chairing meetings of the Committee and ensuring that the Committee is properly organized so that it functions effectively and meets its obligations and responsibilities.
2. Establishing the frequency of Committee meetings, duly convening the same and confirming that quorum is present when required.
3. Working with the CEO, the Executive Vice President, Finance and Chief Financial Officer (the "CFO") of the Corporation, or the Corporate Secretary of the Corporation, as applicable, on the development of agendas and related materials for the meetings.
4. Providing leadership to the Committee and assisting the Committee in ensuring the proper and timely discharge of its responsibilities.
5. Reporting to the Board on the recommendations and decisions of the Committee.

The Chair of the Committee shall review all expense accounts and perquisites of the Chair of the Board and the CEO not less than quarterly to ensure compliance with the Corporation's policies, and shall report to the Committee on an annual basis.

C. Mandate of the Committee

The Committee provides assistance to the Board in fulfilling its oversight responsibilities with respect to: i) the integrity of the Corporation's financial statements and financial reporting process; ii) the systems of internal financial controls and disclosure controls established by management of the Corporation ("Management"); iii) the risk identification and assessment process conducted by Management including the programs established by Management to respond to such risks; iv) the internal audit function; v) compliance with financial, legal and regulatory requirements; and vi) the external auditors' qualifications, independence and performance. In so doing, it is the Committee's responsibility to maintain an open avenue of communication between it and the external auditors, the internal auditors and Management.

The function of the Committee is oversight. Management is responsible for the preparation, presentation and integrity of the interim and annual financial statements and related disclosure documents. Management is also responsible for maintaining appropriate accounting and financial reporting policies and systems of internal controls and disclosure controls and procedures to comply with accounting standards, applicable laws and regulations that provide reasonable assurance that the assets of the Corporation are safeguarded and transactions are authorized, executed, recorded and properly reported.

While the Committee has the responsibilities and powers set forth herein, it is not the duty of the Committee to plan or conduct audits or to determine that the Corporation's financial statements are complete and accurate and in accordance with generally accepted accounting principles. This is the responsibility of Management and the external auditors.

The Committee must also designate at least one member as an "audit committee financial expert." The designation of a member or members as an "audit committee financial expert" is based on that individual's education and experience, which the individual will bring to bear in carrying out his or her duties on the Committee. Designation as an "*audit committee financial expert*" does not impose on such person any duties, obligations and liability that are greater than the duties, obligations and liability imposed on another member of the Committee and Board in the absence of such designation.

Management is also responsible for the identification and management of the Corporation's risks and the development and implementation of policies and procedures to mitigate such risks. The Committee's role is to provide oversight in order to ensure that the Corporation's assets are protected and safeguarded within reasonable business limits. The Committee reports to the Board on its risk oversight responsibilities.

D. Duties and Responsibilities of the Committee

1. Financial Reporting, External Auditors and Financial Planning

A) Duties and Responsibilities Related to Financial Reporting and the Audit Process

(a) Review with Management and the external auditors the Corporation's financial reporting process the work to be conducted in conjunction with the annual audit and the preparation of the financial statements, including, without limitation, the annual audit plan of the external auditors, the judgment of the external auditors as to the quality, not just the acceptability, of and the appropriateness of the Corporation's accounting principles as applied in its financial reporting and the degree of aggressiveness or conservatism of the Corporation's accounting principles and underlying estimates;

(b) Review with Management and the external auditors the Corporation's audited annual financial statements, including the notes thereto, "Management's Discussion and Analysis," the related earnings release, and recommend their approval to the Board for release to the public;

(c) Review with Management and the external auditors the Corporation's interim financial statements, including the notes thereto, "Management's Discussion and Analysis," the related earnings release, and approve their release to the public as required;

(d) In reviewing the financial statements and related financial disclosure, the Committee shall review and discuss with Management and the external auditors:

(i) any changes in accounting principles, practices or policies considering their applicability to the business and financial impact;

(ii) Management's processes for formulating sensitive accounting estimates and the reasonableness of the estimates;

(iii) the use of "pro forma" or "non-comparable" information and the applicable reconciliation;

(iv) alternative treatments of financial information within generally accepted accounting principles that have been discussed between Management and the auditors, ramifications of the use of such alternative disclosures and treatments and the treatment preferred by the external auditors; and

(v) disclosures made to the Committee by the CEO and CFO during their certification process for the relevant periodic/annual report filed with securities regulators to ensure that information required to be disclosed is recorded, processed, summarized and reported within the time periods specified for the reporting period. Obtain assurances from the CEO and CFO as to the adequacy and effectiveness of the Corporation's disclosure controls and procedures and systems of internal control over financial reporting and that any fraud involving Management or other employees who have a significant role in the Corporation's internal controls is reported to the Committee.

(e) In reviewing the financial statements and related financial disclosure, the Committee shall also, with the external auditors:

(i) discuss the cooperation they received from Management during the course of their review and their access to all records, data and information requested; and

(ii) satisfy itself that there are no unresolved issues between Management and the external auditors that could reasonably be expected to materially affect the financial statements.

(f) Review quarterly with senior Management, the Executive Vice President, Legal (or, as necessary, outside legal advisors) of the Corporation, and the Corporation's internal and external auditors, the effectiveness of the Corporation's internal controls to ensure the Corporation is in compliance with legal and regulatory requirements and the Corporation's policies;

(g) Review with Management and the external auditors the processes relating to the assessment of potential fraud, programs and controls to mitigate the risk of fraud, and the processes put in place for monitoring the risks within the targeted areas; and

(h) Discuss with Management and the external auditors any correspondence from or with regulators or governmental agencies, any employee complaints or any published reports that raise material issues regarding the Corporation's financial statements or accounting policies.

B) Duties and Responsibilities Related to the External Auditors

(a) The Committee shall have direct responsibility for the compensation and oversight of the external auditors including nominating the external auditors to the Board for appointment by the shareholders at the Corporation's general annual meeting. In performing its function, the Committee shall:

(i) review and approve annually the external auditors audit plan;

(ii) review and approve the basis and amount of the external auditors' fees and ensure the Corporation has provided appropriate funding for payment of compensation to the external auditors;

(iii) subject to the delegation granted to the Chair of the Committee, pre-approve all audit related services including all non-prohibited non-audit services provided by the external auditors; the Chair of the Committee is authorized to approve all audit related services including non-prohibited non-audit services provided by the external auditors, and shall report all such approvals to the Committee at its next scheduled meeting;

(iv) review and discuss annually with the external auditors all relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors' independence, including, without limitation: (a) requesting, receiving and reviewing, at least annually, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on their independence with the Corporation; (b) discussing with the external auditors any relationships or services that the external auditors believe may affect their objectivity and professional skepticism; (c) reviewing with the external auditors the experience and qualifications of the senior personnel who are providing audit services to the Corporation; (d) reviewing the quality control procedures of the external auditors, including obtaining confirmation that the external auditors are in compliance with Canadian and U.S. regulatory registration requirements; and (e) evaluating the communication and interaction with the external auditor including quality of service considerations;

(v) in the year preceding the change of the lead (or coordinating) audit partner (having primary responsibility for the audit), and in any event not less than every five years, perform a comprehensive review of the external auditor which takes into consideration (a) the impact of the tenure of the audit firm on audit quality, trends in the audit firm's performance and expertise in the industry, incidences of independence threats and the effectiveness of safeguards to mitigate those threats, (b) the responsiveness of the audit firm to changes in the entity's business and suggestions for improvement from regulators, the Committee and/or Management, (c) the consistency and rigour of the professional skepticism applied by the external auditor, and the quality of the engagement team and its communications, review of Canadian Public Accountability Board (CPAB) inspection findings since the previous comprehensive review and how the audit firm responded to these findings, and following this comprehensive review, determine whether the audit firm should be nominated to the Board as the external auditors for appointment by the shareholders at the Corporation's next general annual meeting;

(vi) inform the external auditors and Management that the external auditors shall have direct access to the Committee at all times, as well as the Committee to the external auditors;

(vii) instruct the external auditors that they are ultimately accountable to the Committee as representatives of the shareholders of the Corporation; and

(viii) at least annually, obtain and review the external auditors' report with respect to the auditing firm's internal quality-control procedures, any material issues raised by the most recent internal quality-control review or peer review of the auditing firm, any inquiry or investigation by governmental or professional authorities within the preceding five years undertaken respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with any such issues.

C) Duties and Responsibilities Related to Financial Planning

(a) Review and recommend to the Board for approval the Corporation's issuance and redemption of securities (including the review of all public filings to effect any of the issuances or redemptions), financial commitments and limits, and any material changes underlying any of these commitments;

(b) Review annually the Corporation's annual tax plan;

(c) Receive regular updates with respect to the Corporation's financial obligations, loans, credit facilities, credit position and financial liquidity;

(d) Review annually with Management the Corporation's overall financing plan in support of the Corporation's capital expenditure plan and overall budget/medium range forecast; and

(e) Review with Management at least annually the approach and nature of earnings guidance and financial information to be disclosed to analysts and rating agencies.

2. Internal Audit

(a) Approve whether the internal audit function should be outsourced and if outsourced, approve the audit firm to perform such internal audit service; provided that in no event shall the external auditor be retained to also perform the internal audit function;

(b) Review and consider, as appropriate, any significant reports and recommendations made by internal audit relating to internal audit issues, together with Management's response thereto;

(c) Review annually the scope and plans for the work of the internal audit group, the adequacy of the group's resources, the internal auditors' access to the Corporation's records, property and personnel;

(d) Recognize and advise senior Management that the internal auditors shall have unfettered access to the Committee, as well as the Committee to the internal auditors;

(e) Meet separately with Management, the external auditors and internal auditors to review issues and matters of concern respecting audits and financial reporting;

(f) Review with the senior financial members of Management and the internal audit group the adequacy of the Corporation's systems of internal control and procedures; and

(g) Recommend to the Human Resources Committee of the Board the appointment, termination or transfer of the lead individual responsible for internal audit, provided that if the internal audit function has been, or is being, outsourced to an audit firm, the Committee itself shall approve the appointment, termination or transfer of such audit firm.

3. Risk Management

The Board is responsible for ensuring that the Corporation has adopted processes and key policies for the identification, assessment and management of its principal risks. The Board has delegated to the Committee the responsibility for the oversight of Management's identification, and evaluation, of the Corporation's principal risks, and the implementation of appropriate policies, processes and systems to manage or mitigate the risks within the Corporation's risk appetite. The Committee reports to the Board thereon.

The Committee shall:

(a) Review, at least quarterly, Management's assessment of the Corporation's principal risks; discuss with Management the processes for the identification of these risks and the efficacy of the policies and procedures for mitigating and/or addressing these risks;

(b) Receive and review Managements' quarterly risk update including an update on residual risks;

(c) Review the Corporation's enterprise risk management framework and reporting methodology;

(d) Review annually the Corporation's Financial and Commodity Exposure Management Policies and approve changes to such policies;

(e) Review and approve the Corporation's strategic hedging program, guidelines and risk tolerance;

(f) Review and monitor quarterly results of financial and commodity exposure management activities, including foreign currency and interest rate risk strategies, counterparty credit exposure and the use of derivative instruments;

(g) Review the Corporation's annual insurance program, including the risk retention philosophy, potential exposure and corporate liability protection programs;

(h) Periodically consider the respective roles and responsibilities of the external auditor, the internal audit department, internal and external counsel concerning risk management and review their performance in relation to such roles and responsibilities; and

(i) Annually, together with Management, report and review with the Board:

(i) the Corporation's principal risks and overall risk appetite/profile;

(ii) the Corporation's strategies in addressing its risk profile;

(iii) the processes, policies, procedures and controls in place to manage or mitigate the principal risks; and

(iv) the overall effectiveness of the enterprise risk management process and program.

4. Governance

A) Public Disclosure, Legal and Regulatory Reporting

(a) On behalf of the Committee, the Chair shall review all public disclosure inclusive of material financial information extracted or derived from the Corporation's financial statements prior to dissemination to the public;

(b) Review quarterly with the Executive Vice President, Legal and Corporate Secretary, and, if necessary, outside legal advisors, significant legal, compliance or regulatory matters that may have a material effect on the Corporation's financial statements;

(c) Discuss with the external auditors their perception of the Corporation's financial and accounting personnel, any recommendations which the external auditors may have, including those contained in the Management letter, with respect to improving internal financial controls, choice of accounting principles or management reporting systems, and review all Management letters from the external auditors together with Management's written responses thereto;

(d) Review with Management, the external auditors and internal legal counsel (external counsel if necessary), any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Corporation, and the manner in which these may be or have been disclosed in the financial statements;

(e) Review annually the Insider Trading Policy and approve changes as required; and

(f) Review annually the Corporation's Disclosure Policy and Social Media Policy to ensure continued applicability with the law and the Corporation's disclosure principles.

B) Pension Plan Governance

(a) Review annually the Annual Pension Report and financial statements of the Corporation's pension plans including the actuarial valuation, asset/liability forecast, asset allocation, manager performance and plan operating costs, and reporting thereon to the Board annually; and

(b) Together with the Human Resources Committee of the Board, review annually, and as required, the overall governance of the Corporation's pension plans, approving the broad objectives of the plans, the statement of investment policy, the appointment of investment managers, and reporting thereon to the Board annually.

C) Information Technology – Cyber security and Artificial Intelligence

(a) Receive biannually a system status update with respect to the Corporation's core IT operating systems;

(b) Review annually the Corporation's cyber security programs and their effectiveness. Receive an update on the Corporation's compliance program for cyber threats and security; and

(c) Review periodically developments in respect of artificial and generative artificial intelligence, including opportunities, challenges and/or associated risks which could have a material impact on the execution of the Corporation's strategy or key business objectives.

D) Administrative Responsibilities

(a) Review the annual audit of expense accounts and perquisites of the directors, the CEO and the CEO's direct reports and their use of corporate assets;

(b) Establish procedures for the receipt, retention and treatment of complaints relating to securities law, accounting, internal accounting controls, or auditing matters;

(c) Review incidents, complaints or information reported through the Ethics Help Line addressed to the Committee or relating to securities law, accounting, internal accounting controls, or auditing matters;

(d) Establish procedures for the investigation of complaints or allegations, and, in respect of potentially material complaints or allegations, report to the Board thereon and ensure that appropriate action is taken as necessary to address such matter;

(e) Review and consider any related party transaction and to recommend, if necessary, the use of a standing committee or an ad hoc special committee to assist the Board in the evaluation of any such related party transaction;

(f) Review and approve the Corporation's hiring policies for employees or former employees of the external auditors and monitor the Corporation's adherence to the policy; and

(g) Report annually to shareholders on the work of the Committee during the year.

E. Compliance and Powers of the Committee

(a) The responsibilities of the Committee comply with applicable Canadian laws and regulations, such as the rules of the Canadian Securities Administrators, and with the disclosure and listing requirements of the Toronto Stock Exchange, as they exist on the date hereof. In addition, this Charter complies with applicable U.S. laws, such as the *Sarbanes-Oxley Act* and the rules and regulations adopted thereunder, and with the New York Stock Exchange's corporate governance standards, as they exist on the date hereof.

(b) The Committee may, at the request of the Board or on its own initiative, investigate such other matters as are considered necessary or appropriate in carrying out its mandate.

Appendix "B"

Glossary of Terms

"**AER**" – Alberta Energy Regulator

"**AESO**" – The independent system operator and regulatory authority for the Alberta Interconnected Electric System.

"**BC Hydro**" – British Columbia Hydro and Power Authority

"**BIA**" – *Bankruptcy and Insolvency Act* (Canada)

"**boiler**" – A device for generating steam for power, processing or heating purposes, or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes of the boiler shell.

"**capacity**" – The rated continuous load-carrying ability, expressed in megawatts, of generation equipment.

"**CBCA**" – *Canada Business Corporations Act*.

"**CER**" – Clean Electricity Regulations

"**CO_2e**" – Carbon dioxide equivalent.

"**cogeneration**" – A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating or cooling purposes.

"**combined-cycle**" – An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

"**ECCC**" – Environment and Climate Change Canada

"**FERC**" – Federal Energy Regulatory Commission.

"**GGPPA**" – *Greenhouse Gas Pollution Pricing Act* (Canada).

"**GHG**" – Greenhouse gases that have the potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, and perfluorocarbons.

"**GW**" – Gigawatt – A measure of electric power equal to 1,000 MW.

"**GW/h**" – Gigawatt hour – A measure of electricity consumption equivalent to the use of 1,000 megawatts of power over a period of one hour.

"**IESO**" – Independent Electricity System Operator.

"**IFRS**" – International Financial Reporting Standards.

"**MSA**" – Market Surveillance Administrator.

"**MSHA**" – Mine Safety and Health Administration.

"**MW**" – Megawatt – A measure of electric power equal to 1,000,000 watts.

"**MWh**" – Megawatt-hour – A measure of electricity consumption equivalent to the use of 1,000,000 watts of power over a period of one hour.

"**NEM**" – National Electricity Market

"**NERC**" – North American Electric Reliability Corporation.

"**net capacity**" – The maximum capacity or effective rating, modified for ambient limitations, that a generating unit or power plant can sustain over a specific period, less the capacity used to supply the demand of station service or auxiliary needs.

"**NWIS**" – North West Interconnected System

"**NYSE**" – New York Stock Exchange.

"**opt-in facility**" – A facility that satisfies the eligibility criteria for an opted in facility under Section 4 of the TIER regulation and is voluntarily choosing to participate in the regulation for the purposes of being able to generate emission performance credits.

"**SGM**" – Australian Government's National Safeguard Mechanism

"**TIER**" – Technology Innovation and Emission Reduction Regulation in Alberta.

"**TSX**" – Toronto Stock Exchange.

"**VWAP**" – Volume weighted average price

"**WEM**" – Wholesale Electricity Market

"**WTUC**" – Washington Transportation and Utilities Commission

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-102:
Park Service Comments on BART Proposals (Nov. 2009)

United States Department of the Interior
NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

TAKE PRIDE IN AMERICA

IN REPLY REFER TO:

November 20, 2009

N3615 (2350)

Mr. Stuart A. Clark
Air Quality Program Manager
Department of Ecology
Air Quality Program
PO Box 47600
Lacey, Washington 98504-7600

Dear Mr. Clark:

Thank you for providing information on the Best Available Retrofit Technology (BART) proposals for facilities in Washington that are subject-to-BART. We recognize that much time and effort went into the analyses conducted by the Department of Ecology (Ecology), and we appreciate the time Ecology has taken to discuss the difficult and important issues inherent in this major effort. These comments supplement the statement made by Randy King, Superintendent of Mount Rainier National Park, at the October 13, 2009, public hearing.

In general, we found the Ecology BART analyses to be informative and well-presented. We also recognize that the BART program is relatively new, which presents several challenges to all of us in its implementation. As a national office which conducts BART analyses for all Class I areas in the National Park System, we are able to call upon a growing information base and wish to take this opportunity to make that information available to Ecology. The State of Washington is fortunate to have an extraordinary number of magnificent national parks and wilderness areas within its borders and accessible to its citizens, as well as to numerous visitors. There are many reasons that the law mandates our highest levels of environmental protection for these special areas. National parks and wilderness areas are our natural and cultural heritage. Sociology studies confirm their importance, as do our individual experiences of recreation and renewal. We share your interest in insuring that these magnificent natural areas are protected for the benefit of all. As mentioned in our testimony at the October 13 public hearing, over 1.1 million people visited Mount Rainier National Park in 2008 and visitation as of the end of August of this year is already above the 1 million mark.

Regarding the economic benefits of the national parks, for example, in 2000, when our last visitor surveys were conducted, we learned that visitors to Mount Rainier and Olympic National Parks spent over $120 million in the area. The total economic impact of visitor spending was $95 million in direct sales, $38 million in personal income, $58 million in direct value-added and 2,530 jobs. With multiplier effects, created by the re-circulation of the money spent by tourists, visitor spending generated about $135 million in local sales, and an associated $52 million in personal income, $82 million in value-added and 3,102 jobs. These figures do not include park admission fees or the impacts of the NPS payroll and operations in the area, nor do they include the economic benefits resulting from visitation to North Cascades National Park or to the nine Class I wilderness areas and the Columbia River Gorge National Scenic Area that are also suffering from visibility impairment as a result of emissions from the Washington BART sources.

Our detailed comments on Ecology's BART proposals are enclosed. Based on our review, we believe the following pollution control technologies are technically feasible, cost-effective, and will substantially improve visibility in one of more of the 12 protected areas (including Mount Rainier and Olympic National Parks) included in Ecology's analyses:

- Selective Catalytic Reduction (SCR) to reduce nitrogen oxides emissions from the Centralia Power Plant
- Sodium-based scrubbing to reduce sulfur dioxide emissions from the potlines at the Intalco primary aluminum smelter
- Additional particulate control on the No. 10 Power Boiler and a limit of 0.5% sulfur on fuel oil burned at the Port Townsend Paper Company
- Low-NO_x and Ultra-Low-NO_x Burners proposed by Tesoro (and accepted by Ecology) to reduce nitrogen oxides emissions at its Anacortes refinery. (We recognize the timing issues and suggest that we work together to develop a Reasonable Progress strategy that will achieve the emission reduction goals proposed by Tesoro in a cost-effective, yet expeditious manner.)

Therefore, we ask that you revisit your BART proposals. It appears that that the key issue in these reviews is whether or not to consider the cumulative benefits of reducing emissions for multiple Class I areas. We address that issue below and in our enclosed comments.

Cost-Effectiveness Metrics

BART is not necessarily the most cost-effective solution. Instead, it represents a broad consideration of technical, economic, energy, and environmental (including visibility improvement) factors. We believe that it is appropriate to consider both the degree of visibility improvement in a given Class I area as well as the cumulative effects of improving visibility across all of the Class I areas affected. It simply does not make sense to use the same metric to evaluate the effects of reducing emissions from a BART source that impacts only one Class I area as for a BART source that impacts multiple Class I areas. And, it does not make sense to evaluate impacts at one Class I area, while ignoring

others that are similarly significantly impaired. If we look at only the most-impacted Class I area, we ignore that the other Class I areas are all suffering from impairment to visibility "caused" by the BART source. It follows that, if emissions from the BART source are reduced, the benefits will be spread well beyond only the most-impacted Class I area, and that must be taken into account. .[1]

The BART Guidelines represent an attempt to create a workable approach to estimating visibility impairment. As such, they require several assumptions, simplifications, and shortcuts about when visibility is impaired in a Class I area, and how much impairment is occurring. The Guidelines do not attempt to address the geographic extent of the impairment, but assume that all Class I areas are created equal, and that there is no difference between widespread impacts in a large Class I area and isolated impacts in a small Class I area. To address the problem of geographic extent, we have been looking at the cumulative impacts of a source on all Class I areas affected, as well as the cumulative benefits from reducing emissions. While there are certainly more sophisticated approaches to this problem, we believe that this is the most practical, especially when considering the modeling techniques and information available.

One of the options suggested by the BART Guidelines to evaluate cost-effectiveness is cost/deciview. Compared to the typical control cost analysis in which estimates fall into the range of $2,000 - $10,000 per ton of pollutant removed, spending millions of dollars per deciview (dv) to improve visibility may appear extraordinarily expensive. However, our compilation[2] of BART analyses across the U.S. reveals that the **average cost per dv proposed by either a state or a BART source is $12 - $19 million**,[3] with a maximum of almost $50 million per dv proposed by Colorado at the Martin Drake power plant in Colorado Springs. For example, considering the 12 Class I areas impacted by Centralia, our calculations show that the cost per dv of installing SCR at Centralia would be $5 million, which is relatively cost-effective.

Please note that EPA is proposing to consider the cumulative benefits at multiple Class I areas approach in its own BART determinations. For example, in an August 21, 2009, Advance Notice of Proposed Rulemaking regarding BART for the Navajo and Four Corners power plants, EPA Region 9 discusses an approach to assess visibility improvement that considers multiple Class I areas. And, Oregon considered the cumulative benefits of adding SCR at the Boardman power plant in its determination that SCR would be installed there under the reasonable progress provisions of the Regional Haze Rule. Finally, the Wyoming Department of Environmental Quality explicitly cited[4]

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[1] For example, our analysis, which is described in detail in our enclosed comments, indicates that the cumulative benefits of reducing NO_x emissions from the Centralia power plant are seven times greater than the benefit at Mt. Rainier, the most-impacted Class I area, alone.

[2] Sent to Ecology on 11/13/09 and located at http://www.wrapair.org/forums/ssjf/bart.html

[3] For example, PacifiCorp has stated in its BART analysis for its Bridger Unit #2 that "The incremental cost effectiveness for Scenario 1 compared with the baseline for the Bridger WA, for example, is reasonable at $580,000 per day and $18.5 million per deciview."

[4] As stated by the Wyoming Department of Environmental Quality, "Tuning the existing LNB with OFA and installing SCR is determined to be BART for Unit 3 for NOx based, in part, on the following conclusions: 4. The cumulative 3-year averaged 98th percentile visibility improvement from the baseline

the cumulative benefits to the Bridger and Fitzpatrick Wilderness Areas in its conclusion that adding combustion controls plus SCR to the Naughton Unit #3 is BART.[5]

Over the past several months, we have worked with Ecology staff to evaluate the BART sources under EPA's BART Guidelines, and we are very appreciative of your expertise and assistance. We look forward to continuing this cooperative working relationship as this process advances. We believe that good communication and sharing of information will help expedite this process, and suggest that you contact Don Shepherd at (303) 969-2075 or email him at don_shepherd@nps.gov if you have any questions or comments.

Sincerely,

Christine L. Shaver
Chief, Air Resources Division

Enclosures

cc:
Janice Peterson
Air Resource Specialist
Forest Service
400 N. 34th Street, Suite 201
Seattle, Washington 98103

Rick Graw
Air Resource Management Specialist
USDA Forest Service
Pacific Northwest Region
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P.O. Box 3623
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USEPA Region 10
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Seattle, Washington 98101

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summed across both Class I areas achieved by tuning the existing LNB with OFA, SCR, wet FGD, and installing a new full-scale fabric filter, Post-Control Scenario B, was 1.849 Δdv."

[5] In addition, the Wyoming Department of Environmental Quality (WY DEQ) explicitly considered "visibility improvement from new [control options] summed across the [multiple] Class I areas" in its BART determinations for the Bridger, Johnston, and WYODAK power plants. WY DEQ also determined that SCR would be installed on Bridger units #3 & #4 under the Reasonable Progress provisions of the Regional Haze Rule.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-103:
Park Service Comments on Proposed Haze State Implementation Plan (June 2010)

United States Department of the Interior
NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

TAKE PRIDE IN AMERICA

IN REPLY REFER TO:

June 11, 2010

N3615 (2350)

Ted Sturdevant, Director
Department of Ecology
P.O. Box 47600
Olympia, WA 98504-7600

Dear Mr. Sturdevant:

On April 1, 2010, we received Washington's draft regional haze implementation plan for review. We appreciate the opportunity to work with the State through the development and review of this plan to make progress toward achieving natural visibility conditions at our National Parks and Wilderness Areas.

This letter acknowledges that the U.S. Department of the Interior, National Park Service, in consultation with the U.S. Fish and Wildlife Service, has received and conducted a substantive review of the Washington draft Regional Haze Rule implementation plan in fulfillment of your requirements under the federal regulations 40 CFR 51.308(i)(2). Please note, however, that only the U.S. Environmental Protection Agency (EPA) can make a final determination regarding the document's completeness and, therefore, ability to receive federal approval from EPA.

Our review focused on eight key content areas that were outlined in a letter dated August 1, 2006, that we sent to each State. The content areas reflect priorities for the Federal Land Manager agencies, and our enclosed comments address these priorities. As we have discussed with your staff, we are concerned that the draft implementation plan as written does not meet all the regulatory requirements of the Regional Haze Rule. Washington has proposed reasonable progress goals without conducting the required four factor analysis of possible emission controls. The proposed reasonable progress goals do not reflect substantive improvement in visibility, and in the case of North Cascades National Park and Glacier Peak Wilderness Area, actually project a degradation in visibility by 2018 compared to the 2000-2004 baseline. We also have concerns with the determinations of Best Available Retrofit Technology (BART). Our BART comments supplement those that we provided on November 20, 2009.

We had a constructive discussion with your staff on May 18, 2010, and have offered our assistance in addressing our technical concerns. We look forward to continued dialog as you revise the implementation plan and respond to our comments per section 40 CFR 51.308(i)(3). For further information regarding our comments, please contact Pat Brewer of my staff, at (303) 969-2153.

Again, we appreciate the opportunity to work closely with the State of Washington to improve visibility in our Class I national parks and wilderness areas.

Sincerely,

for Christine L. Shaver
Chief, Air Resources Division

Enclosure

cc: Mahbubul Islam
Manager, State and Tribal Air Programs Unit
U.S. EPA Region 10
1200 Sixth Avenue
Seattle, WA 98101

Stuart Clark
Manager, Air Quality Program
Department of Ecology
P.B. Box 47600
Olympia, Washington 98504-7600

National Park Service Comments
Washington Draft State Implementation Plan for Regional Haze
June 11, 2010

General Comments

Washington Department of Ecology (Ecology) has provided a clearly written draft regional haze State Implementation Plan (SIP). The draft plan contains several, but not all, of the key policy elements that we outlined in our August 2006 letter to the States. Ecology has demonstrated using the IMPROVE monitoring data and technical analyses provided by the Western Regional Air Partnership (WRAP) that Washington understands the causes of visibility impairment at the Class I areas in Washington.

The draft SIP is missing the required analysis of the four statutory factors to set reasonable progress goals and lacks a substantive long-term strategy for improving visibility in Class I areas in Washington. Ecology is taking few actions beyond reporting existing federal or previous state actions. Ecology needs to do more to demonstrate its commitment to improving visibility.

Ecology's Best Available Retrofit Technology (BART) determinations addressed some of our procedural concerns, but made no changes in control requirements from the draft BART determinations.

We provide more detailed comments on these concerns below. We also agree with comments provided by the Forest Service. We are willing and would welcome the opportunity to assist Ecology to implement the recommended analyses prior to submitting the final SIP to EPA.

Specific Comments

Chapter 5 Baseline and Natural Conditions

It would be helpful to look at daily time series data for each IMPROVE monitor for each year to better understand the frequency of contributions from fire (e.g., few major events vs multiple smaller events) and to better characterize the seasonal variation in contributions from nitrate and sulfate. Daily time series plots can be generated from the VIEWS website (http://views.cira.colostate.edu/web/).

Chapter 6 Emissions Inventory

WRAP provided several inventories to the western states to support regional planning. Ecology has chosen to discuss only two of the available WRAP inventory versions, 2002 Plan d (Plan02d) and 2018 Projected Reasonable Progress version a (PRP18a). It would be helpful to report that a 2002 actual inventory was used for model performance evaluation for the 2002 base year and to clarify how those emissions differed from the 2000-2004 average emissions used in Plan 02d.

Ecology should provide more discussion of the basis for differences between the 2002 Plan02d and the 2018 PRP18a inventory. Please identify the specific On the Books controls that account for the reduction in point source sulfur dioxide (SO_2). Please define whether the PRP18a inventory includes all the controls determined to be BART for sources subject to BART in Washington.

Please discuss the basis for increases between 2002 and 2018 in emissions of SO_2 from area sources and increases in emissions of nitrogen oxides (NO_x), volatile organic compounds (VOC), primary organic carbon (OC), and elemental carbon (EC) from point and area sources. It is difficult to claim progress in improving visibility when Washington emissions are increasing rather than decreasing.

Please clarify why Ecology chose to use the earlier 2018 PRP18a inventory rather than the more recent 2018 PRP18b inventory. We recommend that Ecology use the PRP18b inventory and modeling results. At a minimum, Ecology should explain the significant differences between the PRP18a and PRP18b inventories and define which inventory is more accurate. For example, total projected SO_2 emissions from Washington point sources were 12,262 tons lower in the PRP18b inventory than in the PRP18a inventory. Total NO_x emissions from point sources were 5,250 tons lower in PRP18b than PRP18a. Are these differences due to emissions controls or changes in inventory methods? Did Ecology or WRAP generate these inventory changes?

Chapter 7 WRAP Modeling

Section 7.3 on model performance provides very little information to judge the confidence to place in the modeling results reported over the next 50 pages. It is preferable for Ecology to include model performance charts for sulfate, nitrate, and organic carbon. At a minimum, Ecology should discuss how well the regional models represent meteorology and air quality at the IMPROVE monitors in Washington.

The last sentence in section 7.3 is incomplete.

Section 7.4 accurately discusses the Particulate Source Apportionment Technology (PSAT) modeling and the Weighted Emissions Potential analyses (WEP). In Section 7.4.3 it is important for Ecology to clarify the significant differences between the inventory versions reported in Section 6 (WRAP 2002 Plan02d and 2018 PRP18a), the earlier inventories used for the PSAT modeling (2002 Plan02c and 2018 base b) and the later 2018 inventory used in the WEP analyses (2002 Plan02d and 2018 PRP18b).

Please correct the figure title for Figure 7-3 which refers to WEP results not PSAT results. The last two sentences in Section 7.4.3 appear contradictory.

Chapter 8 Source Apportionment

WRAP's PSAT results for sulfate and nitrate source apportionment and the WRAP WEP analyses are accurately reported. Residence time analyses can assist in defining source areas that

most frequently impact Class I areas. In addition to the residence time plots available on the WRAP Technical Support System (TSS) under the WEP analyses, residence time plots are also provided under the Causes of Haze technical archive:
http://www.coha.dri.edu/images/backtraj/wa_w20_0500m_backtraj_northcascades.gif.

Chapter 9 Reasonable Progress Goals

Ecology has not met the requirements of the regional haze rule Section § 51.308 (d) (1):

> "The reasonable Progress goals must provide for an improvement in visibility for the most impaired days…
>
> (i) In establishing a reasonable progress goal for any mandatory Class I Federal area within the State, the State must:
>
> (A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal."

Ecology set reasonable progress goals for the Class I areas in Washington the same as the WRAP PRP18a modeling results. DOE did not consider the four statutory factors. Modeled visibility in 2018 does not meet the uniform rate of progress for 2018. At North Cascades National Park and Glacier Peak Wilderness Area, visibility is projected to degrade by 2018. Both sulfate and organic carbon are projected to increase at North Cascades National Park in 2018 compared to 2002. This result does not comply with Section § 51.308 (d) (1). Ecology needs to explain the basis for these results.

It is difficult to see how Ecology can conclude that the existing controls are sufficient to demonstrate reasonable progress, especially when point and area source emissions in Washington are projected to increase by 2018.

Tesoro Refining and Marketing Company originally proposed to install and operate low NOx burners or ultra low NOx burners on process heaters by 2018 as part of their Best Available Retrofit Technology (BART) proposal. Ecology found the proposed controls to be technically and economically feasible. Since Tesoro proposed to install controls on two heaters during a regularly scheduled maintenance outage in 2017, these controls were determined to be too late to meet BART requirements and not required in Tesoro's permit. We ask Ecology to require by permit that these controls be operational by 2018 as part of the current reasonable progress demonstration.

The regional haze rule Section § 51.308 (d) (1) (vi) instructs:

> "The State may not adopt a reasonable progress goal that represents less visibility improvement than is expected to result from implementation of other requirements of the CAA during the applicable planning period."

Ecology is using the WRAP PRP18a inventory for reasonable progress goals, yet the more recent WRAP PRP18b inventory has lower emissions and the PRP18b modeling results project slightly better visibility at the Class I areas than the PRP18a modeling results. If the PRP18b inventory and modeling results provide a more accurate representation of visibility benefits from expected controls by 2018, then Ecology should cite the PRP18b modeling results.

For the reasonable progress analysis, Ecology should identify the major sources in Washington that may contribute to visibility impairment in Class I areas and potential future controls.

Using the WRAP Emissions Data Management System (EDMS), in the attached table we identified 37 individual units in Washington that have projected 2018 emissions greater than 350 tons per year of either SO_2 or NO_x in the WRAP PRP18a inventory. (Facility name is listed more than once if there are multiple processes at one facility.)

Ecology could use data available through the WRAP EDMS and WRAP WEP to qualitatively rank the potential contributions of Washington point sources to Class I areas. Emissions, distance from the source to the Class I area, and residence time of the grid cell where the source is located can be used to rank the relative importance of specific point sources for consideration in a reasonable progress analysis. Such an analysis is advisable to prioritize DOE's intended control analysis under the long-term strategy. We are available to assist in such an analysis.

Chapter 10 Long Term Strategy

The long-term strategy should include a discussion of the BART controls. Even if exempted from BART, industrial sources may still need to reduce emissions to make reasonable progress toward improving visibility.

Ecology indicates that Washington's silvicultural Smoke Management Plan was included in the 1999 SIP for Reasonably Attributable Visibility Impairment (RAVI). Please clarify if the Smoke Management Plan has been updated since 1999. Please provide additional discussion of the state's control requirements for agricultural burning. More discussion is needed to demonstrate how these smoke management programs restrict emissions.

Ecology discusses that Washington has already implemented a program to address residential wood combustion but does not discuss that the inventory provided by WRAP for this sector is increasing, not decreasing. Please clarify whether the WRAP PRP18a inventory accounts for Washington's residential wood control programs.

Chapter 11 Best Available Retrofit Technology (BART)

Ecology has not fully addressed our previous comments (November 20, 2009).

BART sources in Washington impact several Class I areas. Cumulative visibility impacts need to be considered when determining the appropriate level of control for BART. Ecology's response that there is no single clearly defined method to consider cumulative impacts does not

address our concern. The visibility benefits of controlling a source that impacts 12 Class I areas are greater than the benefits of controlling a source that impacts 1 Class I area, and Ecology's BART analyses should consider cumulative, multi-park impacts. We are willing to assist you in calculating cumulative impacts and multi-park benefits of control scenarios.

Our detailed comments on the proposed BART determinations are provided in the attached analyses and summarized below.

Alcoa Wenatchee: We strongly disagree with using an ultra fine modeling grid to exempt Alcoa Wenatchee from BART eligibility. Control options for this source should have been evaluated.

Centralia:

- We believe that Selective Catalytic Reduction (SCR) is both technically feasible and cost effective to reduce visibility impacts and should be determined to be BART for Centralia.
- TransAlta assumes that due to space constraints, SCR would have to be located on top of the electrostatic precipitator (ESP). TransAlta did not consider the feasibility of a downstream location. Ecology should not have eliminated low-dust and tail-end SCR with resized ductwork as feasible options.
- Ecology has underestimated the ability of SCR to reduce emissions. Ecology assumes that SCR can achieve an annual emissions limit of 0.07 lb/mmBtu or 70% NOx reduction. EPA's Clean Air Markets data base demonstrates that 19 units are achieving an annual emissions rate of 0.05 lb/mmBtu or 90% NOx removal. By underestimating SCR efficiency, cost effectiveness is underestimated.
- Costs of SCR installation are overestimated. The EPA Control Cost manual should have been used as recommended by EPA in the BART guidelines. Several cost items were included in the analysis that are not allowed in the Cost Manual.
- With higher removal efficiency and lower total costs, NPS estimated a reasonable cost effectiveness at $5622/ton, compared to $9091/ton estimated by TransAlta's consultant.
- TranAlta underestimated the visibility benefits of SCR. TransAlta has lowered sulfur dioxide emissions by burning low sulfur coal from Powder River Basin in Wyoming (called FlexFuel project). TransAlta evaluated the visibility benefits of Selective Noncatalytic Reduction (SNCR) with FlexFuel but evaluated SCR without the benefit of FlexFuel. Thus the benefits of SCR are underrepresented.
- We have previously asked Ecology to consider the cumulative visibility impacts of TransAlta on the 12 Class I areas that are within 300 km of the facility, and the potential visibility improvements in those areas from the various control alternatives.

Tesoro:

- Ecology found that NOx emissions controls originally proposed as BART by Tesoro are appropriate and cost effective to implement in the 2017-2018 timeframe. Because these controls cannot be installed by 2015, Ecology determined that they did not meet the BART requirements. Ecology should require these controls to be installed by 2018 as part of reasonable progress.

Port Townsend:

- Ecology must evaluate all technically-feasible and proposed options against the proposed BART limits if these are higher than current emissions limits.
- Ecology must evaluate the visibility impacts of switching to lower sulfur fuels.
- Ecology should have evaluated upgrades to existing control equipment.
- We believe a wet Electrostatic Precipitator for Power Boiler #10 is cost effective and represents BART.

Intalco:

- Costs of Limestone Slurry Forced Oxidation were overestimated.
- Intalco and Ecology should better explain why seawater scrubbing and sodium-based scrubbing were rejected for potline SO_2 emissions.

Conclusions

We would like to see Ecology make a more substantive effort to reduce emissions to improve visibility. We are willing to assist Ecology to address the concerns raised in this review.

Washington Point Source 2018 Emissions SO2 or NOx Greater than 350 Tons/Year
(from Western Regional Air Partnership; plant name is listed more than once if there are multiple units and/or processes at one facility)

Source Category	Source Category	Plant Name	2018 SO2 tons/yr	2018 NOx tons/yr
Primary Metal Production	Aluminum Ore (Electro-reduction)	Aluminum Co Of America Wenatchee Works	3,026	56
		Goldendale Aluminum	433	63
		Intalco Aluminum Corp Ferndale	4,734	29
Pulp and Paper and Wood Products	Sulfate (Kraft) Pulping	Boise Cascade	3,873	609
		Fort James Camas Llc	12	589
		Longview Fibre	125	815
		Pt Townsend Paper	448	374
		Simpson Tacoma Kraft	557	543
		Weyerhaeuser Co	67	839
	Sulfite Pulping	Fort James Camas Llc	8	480
		Weyerhaeuser Co.	284	572
Petroleum Industry	Process Heaters	Bp Cherry Point Refinery	904	1,684
		Conoco Phillips	744	640
		Puget Sound Refining Company	16	577
		Tesoro Northwest Company	1,100	761
	Flares	Puget Sound Refining Company	665	29
	Catalytic Cracking Units	Puget Sound Refining Company	1,571	
	Petroleum Coke Calcining	Bp Cherry Point Refinery	245	843
	Blowdown Systems	Conoco Phillips	559	393
Mineral Products	Cement Manufacturing (Wet Process)	Lafarge North America Inc	1,209	3,528
	Cement Manufacturing (Dry Process)	Ash Grove Cement Co, E Marginal	312	1,597
	Glass Manufacture	Cardinal FG	72	830
		Saint-Gobain Containers Inc	193	669
	Lime Manufacture	Graymont Western Us Inc Total	151	394
Chemical Manufacturing	Nitric Acid	Agrium Us Inc	0	415

Source Category	Source Category	Plant Name	2018 SO2 tons/yr	2018 NOx tons/yr
Electric Generation	Bituminous/ Subbituminous Coal	Transalta Centralia Generation	2,491	14,477
	Wood/Bark Waste	Avista	9	660
	Residual Oil	Daishowa America	412	71
Industrial Combustion Boilers	Process Gas	Conoco Phillips	1,223	103
		Longview Fibre	1,898	27
		Puget Sound Refining Company	4	629
		Tesoro Northwest Company	3,775	1,650
	Wood/Bark Waste	Kimberly-Clark Corporation	499	571
		Weyerhaeuser Co	821	1,666
	Residual Oil	Tesoro Northwest Company	707	117
	Natural Gas	Longview Fibre	1	499
Solid Waste Disposal - Government	Municipal Incineration	Waste To Energy	15	451

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-104:
BART Order No. 6426 (June 18, 2010)

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
PO Box 47600 • Olympia, WA 98504-7600 • 360-407-6000
711 for Washington Relay Service • Persons with a speech disability can call 877-833-6341

June 18, 2010

Mr. Lou Florence,
TransAlta Centralia Generation LLC
913 Big Hanaford Road
Centralia, WA 9853

Dear Mr. Florence:

Regional Haze Best Available Retrofit Technology (BART) Determination
Order No. 6426

Best Available Retrofit Technology (BART) is required to reduce the regional haze impacts of emissions of your facility. The enclosed order #6426 contains our BART determination for your facility including a schedule for compliance.

If you have questions or requests relating to this order, please contact Alan Newman at (360) 407-6810 or by mail at the address above.

Sincerely,

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

jj/lb

Enclosure

cc: Clint Lamoreaux, SWCAA
Alan Newman, Ecology
Richard DeBolt, TransAlta

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY

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

TO: Mr. Lou Florence,
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.

B. BART emission limitations for sulfur dioxide and particulate 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 low NO_x burners with separated and close coupled over fire air systems (aka LNC3).

   b. Use of a sub-bituminous Powder River Basin coal or other coal that will achieve similar emission rates.

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

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, and the BART Analysis for the Centralia Power Plant, June 2008 and the BART Analysis Supplement, December 2008.

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

BART Emission Limitations

1. Nitrogen Dioxide Emissions

1.1. Starting no later than the date in Condition 2, emissions of nitrogen dioxide from the two coal-fired utility steam generating units at the Centralia Power Plant are limited to a maximum of:

1.1.1. 0.24 lb/MMBtu, 30 day rolling average, both units averaged together for days (i.e., midnight to midnight) when either unit's generating load is 360 MW gross or greater.

1.1.2. In the event that during a given 30 day period, only one unit operated, the average of both units will be the 30 day average emission rate for the operating boiler.

1.2. Compliance will be determined by use of a continuous emission monitoring system.

1.3. Coal used shall be a sub-bituminous coal from the Powder River Basin or other coal that will achieve similar emission rates.

Schedule for Compliance

2. Compliance with the 30-day rolling average nitrogen dioxide emission limitation begins on the date of issuance of this Order, based on emissions for the prior 30 day period.

3. Determination of compliance with the rolling annual average nitrogen and sulfur coal content limitation will commence at midnight on the 365th day after issuance of this Order, based on coal nitrogen and sulfur content testing during the prior year.

Monitoring and Recordkeeping Requirements

4. Nitrogen Dioxide

4.1. Nitrogen dioxide emissions are to be quantified by means of a continuous emission monitoring system, consisting of a continuous nitrogen dioxide monitor, and a continuous flow rate monitor.

4.2. The continuous monitoring system shall comply with Condition M9 of the Centralia Power Plant's Air Operating Permit, SW98-8- R3 (issued September 16, 2009) ("Air Operating Permit") and corresponding monitoring conditions in future renewals of the Air Operating Permit.

5. Missing data requirements for nitrogen dioxide emission monitoring required by this order

5.1. For a unit with less than 12 continuous hours of missing CEM data, the substituted hourly emission rate will be the higher of (a) the average of emissions during the hour before and the hour after the period of missing data or (b) the average of emissions from the previous 720 operating hours of quality-assured data.

5.2. For a unit with 12 or more continuous hours of missing CEM data, the substituted hourly emission rate will be based on the 90th percentile of the previous 720 operating hours of quality-assured data.

5.3. Those 30 day periods which include substitute data for calculating 30 day averages shall be indicated in the emissions information reported in Condition 7.

6. Coal Quality Monitoring

6.1. Coal nitrogen and sulfur content shall be determined by taking a sampling coal conveyed by the transfer belt 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.

6.2. 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 shall be taken following ASTM Method D2234/D2234M-07.

6.3. 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.

6.4. 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

7. Malfunction of the emission control system must, at a minimum, be documented in writing and submitted to SWCAA and Ecology with the emissions monitoring data per Condition 7. Additional recordkeeping and notifications related to excess emissions may also be required by SWCAA regulation.

8. Continuous emission monitoring data shall be submitted to Ecology and to the SWCAA in accordance with condition R3 of the Centralia Plant's Air Operating Permit; SW98-8- R3 (issued September 16, 2009). In addition to the information required in condition R3, the report will include the 30 day rolling average lb. NOx/MMBtu and tons of NOx emitted during the current calendar year. The submittal shall be sent electronically in a format acceptable to the SWCAA. Reporting to Ecology under this condition will end if the Order has been rescinded as provided in Condition 10, below.

9. Coal nitrogen and sulfur content information shall be submitted to Ecology and to the SWCAA in accordance with schedule in condition R3 of the Centralia Plant's Air Operating Permit; SW98-8-R3 (issued September 16, 2009).

    9.1. Coal nitrogen and sulfur reporting during the first year (Oct. 30, 2009 through Oct. 30, 2010) shall include the date each coal sample is taken, the nitrogen and sulfur content of each coal sample analyzed, the running average content and the maximum and minimum concentrations found.

    9.2. After the first year, the report shall include the rolling annual averages for nitrogen and sulfur content plus the maximum and minimum concentrations in the prior year.

    9.2.1. The weekly coal sample test results shall be retained for at least 5 years and available for review by Ecology or SWWCAA upon request.

10. TransAlta may request this Order be rescinded after all of the following occur:

    10.1. The emission limitations in this Order have been incorporated into an enforceable order or permit issued by SWCAA under the criteria of RCW 70.94.152 or 70.94.153 and SWCAA implementing regulations, provided that BART emission limits for the Centralia Power Plant will not be reanalyzed or reconsidered in connection with SWCAA's issuance of such enforceable order or permit.

    10.2. The emission limitations in the enforceable order or permit have been incorporated into the Air Operating Permit issued by SWCAA for the Centralia Power Plant.

    10.3. EPA has incorporated the Order into the Regional Haze State Implementation Plan.

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

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

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

If you appeal you must:

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

To file your appeal with the Pollution Control Hearing Board:

Mail appeal to:

The Pollution Control Hearings Board
PO Box 40903
Olympia, WA 98504-0903

OR

Deliver your appeal in person to:

The Pollution Control Hearings Board
4224–6th Avenue SE Rowe Six, Bldg 2
Lacey, WA 98503

To serve your appeal on the Department of Ecology:

Mail appeal to:

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

OR

Deliver your appeal in person to:

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

And send a copy of your appeal packet to:

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

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

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

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

DATED this 18 day of June, 2010 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	)))))	Order No. 202-25-11

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 1-105:
Sierra Club Comments on Proposed Haze State Implementation Plan

EARTHJUSTICE

ALASKA CALIFORNIA FLORIDA MID-PACIFIC NORTHEAST NORTHERN ROCKIES
NORTHWEST ROCKY MOUNTAIN WASHINGTON, DC INTERNATIONAL

October 5, 2010

Email: AQComments@ecy.wa.gov
Doug Schneider
Department of Ecology
Air Quality Program
P.O. Box 47600
Olympia, WA 98504-7600

RE: Washington Proposed Regional Haze State Implementation Plan Comments by National Parks Conservation Association, Sierra Club, and Northwest Environmental Defense Center

Dear Mr. Schneider:

Earthjustice submits these comments on the Washington Department of Ecology's ("Ecology") Regional Haze State Implementation Plan ("Haze Plan") on behalf of the National Parks Conservation Association, Sierra Club—Cascade Chapter, and Northwest Environmental Defense Center (collectively "Conservation Organizations").

The National Parks Conservation Association ("NPCA") is a national organization whose mission is to protect and enhance America's National Parks for present and future generations. NPCA performs its work through advocacy and education. NPCA has over 340,000 members nationwide with its main office in Washington, D.C. and 24 regional and field offices. NPCA's regional Northwest office is located in Seattle where is works on a variety of issues affecting Northwest National Parks such as North Cascades, Olympic, and Mt. Rainier National Parks. NPCA is active nation-wide in advocating for strong air quality requirements in our parks, including submission of petitions and comments relating to visibility issues, regional haze State Implementation Plans, global warming and mercury impacts on parks, and emissions from individual power plants and other sources of pollutants affecting National Parks. NPCA's members live, work, and recreate in all the National Parks of the Northwest, including those directly affected by the TransAlta coal-fired power plant in Centralia, Washington.

The Sierra Club is a national organization founded in 1892, with more than 60 chapters throughout the U.S., including the Cascade Chapter located in Seattle Washington. The Cascade Chapter's membership resides and recreates throughout the state. Sierra Club is devoted to the study and protection of the earth's scenic and ecological resources—mountains, wetlands, woodlands, wild shores and rivers, deserts, plains, and their wild flora and fauna. An important part of Sierra Club's current work, at both the national and chapter level, is its Beyond Coal campaign which, among other things, focuses on retiring and reforming old coal-fired power plants that are significant contributors to health-harming soot and smog pollution, global warming pollutants, and hazardous pollutants such as mercury.

705 SECOND AVENUE, SUITE 203 SEATTLE, WA 98104-1711
T: 206.343.7340 F: 206.343.1526 E: eajuswa@earthjustice.org W: www.earthjustice.org

The Northwest Environmental Defense Center ("NEDC") is a regional non-profit organization, based in Portland, Oregon. NEDC works to protect the environment and natural resources of the Pacific Northwest, by providing legal support to individuals and grassroots organizations with environmental concerns, and engaging in litigation independently or in conjunction with other environmental groups. NEDC also provides valuable hands-on experience for students seeking to enhance their education in environmental law. NEDC is regularly involved in efforts to maintain or enhance the air quality of the Pacific Northwest, by serving as a watchdog over Oregon's Department of Environmental Quality, Washington's Department of Ecology and each state's respective permitting processes. Student volunteers regularly comment on proposals for new air permits and permit modifications, monitor current permits in search of violations, and stay on top of major air quality issues, such as changes in administrative regulations.

Ecology's proposed Regional Haze SIP fails to meet the legal requirements of the Clean Air Act and federal regulations, and fails to adequately control emissions that cause haze pollutions. As detailed below, the Conservation Organizations respectfully request that the proposed Haze Plan be revised to adequately control these pollutants.

BACKGROUND

Regional haze results from small particles in the atmosphere that impair a viewer's ability to see long distances, color, and geologic formations. While some haze-causing particles result from natural processes, most result from anthropogenic sources of pollution. Haze-forming pollutants, including sulfur dioxide (SO2), nitrogen oxides (NOx), particulate matter (PM), volatile organic compounds (VOCs), and ammonia (NH3), contribute directly to haze or form haze after breaking down in the atmosphere. These air pollutants contribute to the deterioration of air quality and reduced visibility in our national parks and wilderness areas. Visibility impairment is measured in deciviews, which is a measure of the perceptible change in visibility. The higher a deciview value is, the worse the visibility impairment.

The same pollutants that contribute to visibility impairment also harm public health. The fine particulates that cause regional haze, PM2.5, are a major public health concern because they can be inhaled deep into the lungs. Fine particulate can cause decreased lung function, aggravate asthma, and premature death in people with heart or lung disease. NOx and VOCs can also be precursors to ground level ozone, or smog. Ground level ozone is associated with respiratory diseases, asthma attacks, and decreased lung function.[1] The U.S. Environmental Protection Agency (EPA) has found that in 2015, the Regional Haze Rule also will provide substantial health benefits valued at $8.4 – $9.8 billion annually—preventing 1,600 premature deaths, 2,200 non-fatal heart attacks, 960 hospital admissions, and over 1 million lost school and work days.

[1] *See* http://www.nature.nps.gov/stats/index.cfm.

The total annual cost will range from 1.4 – 1.5 billion dollars.[2] These benefits are estimated under the assumption that the Regional Haze Rule will be implemented as intended. Unfortunately, these public health benefits will not be realized for the citizens of Washington if the State of Washington does not revise its plan to meet regional haze protection goals and requirements as set forth below.

Congress declared as the national goal, the "prevention of any future, and the remedying of any existing, impairment of visibility in the mandatory class I Federal areas which impairment results from manmade air pollution." 42 U.S.C. §7491(a)(1). "Manmade air pollution" is defined as "air pollution which results directly or indirectly from human activities." 42 U.S.C. §7491(g)(3). Congress adopted the visibility protection program to protect the "intrinsic beauty and historical and archeological treasures" of specific public lands.[3] To protect these treasures, the regional haze program establishes a regulatory floor and requires states to design and implement programs at least as stringent as the national floor to curb haze causing emissions located within their jurisdictions. In order to meet this goal, a state is required to design an implementation plan to reduce, and ultimately eliminate, haze from air pollution sources within its borders that may reasonably be anticipated to cause or contribute to visibility impairment for any protected area located within or beyond that state's boundaries. In creating and implementing the plan, a state has an unparalleled opportunity to protect and restore regional air quality by curbing visibility impairing emissions from some of its oldest and most polluting facilities.

Each state implementation plan ("SIP") must provide emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress towards meeting the national goal. 42 U.S.C. § 7491(b)(2). Two of the most critical features of a SIP are requirements for (1) the installation of BART for delineated major stationary sources of pollution and (2) a long-term strategy for making reasonable progress towards the national visibility goal. 42 U.S.C. § 7491(b)(2)(A) & (B).

THE WASHINGTON HAZE PLAN IS LEGALLY AND TECHNICALLY DEFICIENT

The Washington Haze Plan fails to require sufficient reductions in visibility-impairing pollutants from major polluting sources, falls far short of meeting reasonable progress goals, and fails to provide a long term strategy that would meet reasonable progress goals. Washington's Haze Plan shows visibility actually *degrading* at North Cascades National Park and Glacier Peak

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[2] EPA, Fact Sheet, *Final Regional Haze Regulations for Protection of Visibility in National Parks and Wilderness Areas* (June 2, 1999) at http://www.epa.gov/visibility/fs_2005_6_15.html.

[3] *See* H.R. REP. NO. 95-294, at 203–04 (1977).

Wilderness Area by the first 2018 milestone. Thus, the Haze Plan utterly fails to reflect *any* progress toward cleaning up visibility at these two Class I areas.

The plan also fails to provide for adequate reasonable progress toward cleaning up visibility impairment at most of its other Class I areas. Ecology found that, at the rate of emission reductions planned for or required by the state regional haze plan, it would take Olympic National Park *323* years to reach natural visibility conditions.[4] Ecology projects it would take *87* years for the Alpine Lakes Wilderness Area to reach natural visibility conditions and *86* years for Mount Rainier National Park.[5] And, amazingly, Ecology predicts it would take the Pasaytan Wilderness *698* years to reach natural visibility conditions.[6] These rates of progress are so ridiculously slow, they are not progress at all, much less reasonable progress.

As addressed below, the State can and must achieve much greater emission reductions in haze causing pollution with available control technologies and/or by imposing more stringent emission limits reflective of the best level of continuous emission reduction in its Best Available Retrofit Technology (BART) determinations. While it may be true that some of the pollution responsible for haze in the State's Class I areas is due to sources outside of Washington's control, that does not relieve Washington from the requirement to subject industrial sources within Washington to BART emission limits reflective of the best degree of continuous emission reduction achievable, nor does it relieve the State from adopting other measures to improve visibility in Washington.

In addition, the long-term strategy must ensure appropriate BART requirements and other measures are implemented to improve visibility in Washington and other downwind states' Class I areas to ensure that the Haze Plan will attain the goal of meet its share of the emission reductions needed to meet the reasonable progress goals for the area. Such additional measures must include consideration of source retirement and replacement. *See* 40 C.F.R. § 51.308(d)(3)(v)(D).

The National Park Service has submitted extensive comments to Ecology detailing the deficiencies in its regional haze plan on June 11, 2010 and on November 20, 2009.[7] Earthjustice submitted comments to Ecology on its Proposed Ecology/TransAlta Settlement Agreement

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[4] *See* Washington Proposed Regional Haze Plan, Chapter 9 at 9-7.

[5] *Id.* at 9-19 and 9-22.

[6] *Id.* at 9-30. Again, the requirement in the law is to reach natural conditions by 2064, 32 years sooner than Ecology apparently intends for Mt. Rainier National Park and 644 years sooner than Ecology apparently intends for the Pasayten Wilderness.

[7] *See* Exhibits 1 and 2 to this letter.

regarding best available retrofit technology (BART) requirements for the TransAlta-owned Centralia coal-fired power plant as well as mercury, and included expert comments by Dr. Ranajit Sahu that discussed the deficiencies in the BART requirements for the TransAlta Centralia Power Plant (the "TransAlta Centralia Plant").[8] EPA also submitted a comment letter to Ecology on June 30, 2010 identifying several deficiencies in the Washington Haze Plan and proposed BART requirements.[9] Ecology has failed to respond adequately to the majority of these comments. Those previous comments are incorporated herein and provide the following additional comments and information to Ecology regarding their deeply-flawed Haze Plan.

I. BEST AVAILABLE RETROFIT TECHNOLOGY REQUIREMENTS ARE NOT MET IN THE WASHINGTON HAZE PLAN.

States are required to submit SIPs if they host federally protected areas or the emissions of a facility located within a State "may be reasonably be anticipated to cause or contribute to any impairment of visibility" for a protected area located beyond their borders. 42 U.S.C. § 7491 (b)(2). A SIP must contain "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress towards meeting the national goal…," including BART requirements for all eligible sources and a long-term strategy for making reasonable progress towards meeting the national goal. 42 U.S.C. § 7491(b)(2)(A) &(B).

BART is defined as an emission limitation:

> **. . .based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility.** The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement invisibility which may reasonably be anticipated to result from the use of such technology.

40 C.F.R. §51.301 (emphasis added).

BART limits are required for major stationary sources that were in existence on August 7, 1977 and began operating after August 7, 1962 and that emit air pollutants that may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I area.

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[8] A copy of our November 9, 2009 comment letter is included as Exhibit 3, and a copy of Dr. Sahu's expert report is included as Exhibit 4.

[9] See Exhibit 5 to this letter.

42 U.S.C. § 7491(b)(2)(A). The term "major stationary source" is defined as a source that has the potential to emit 250 tons or more of any pollutant and falls within one of 26 categories of industrial sources defined by the Act. 42 U.S.C. § 7491(g)(7). A BART-eligible source is one that meets the above criteria and is responsible for an impact on visibility in a Class I area of 0.5 deciview or more. 40 C.F.R. Part 51, Appendix Y. BART must be installed and operated no later than five years after the SIP approval. 40 C.F.R. § 51.302(c)(4)(iv).

As discussed in detail below, Washington has clearly not required emissions controls and limits that reflect BART for the BART-eligible sources.

A. BART for the TransAlta Centralia Coal-Fired Power Plant.

The TransAlta Centralia Plant is the largest emitter of regional haze pollutants of all of Washington's BART-eligible sources. Nonetheless, Ecology proposes nothing more than the status quo as BART at this facility. Given that the Washington regional haze plan so woefully fails to even come close to meeting its 2018 reasonable progress goals for any of its Class I areas, Ecology must conduct a proper evaluation of BART for the Centralia plant and require the installation of a selective catalytic reduction (SCR) system is BART for the NOx emissions at the TransAlta Centralia Plant.

1. The NOx BART determination for the TransAlta Centralia Plant is not at least as stringent as the presumptive NOx BART limits for tangentially–fired boilers.

Pursuant to 40 C.F.R. § 51.308(e)(1)(ii)(B), the determination of BART for fossil-fuel fired power plants with more than 750 MW generating capacity, such as the TransAlta Centralia Plant, must be made in accordance with the EPA's Guidelines for BART Determinations Under the Regional Haze Rule in 40 C.F.R. Part 51, Appendix Y. The EPA's BART Guidelines include presumptive BART limits for SO2 and for NOx. Therefore, these presumptive BART limits do not take the place of a case-by-case BART analysis. EPA has determined that these levels of emissions should be cost-effective, but lower emission limits may also be cost-effective. EPA's presumptive limit simply sets the minimum. For tangentially-fired boilers burning Powder River Basin coal, such as the TransAlta Centralia Plant's boilers, EPA's BART Guidelines identify 0.15 lb/MMBtu as the presumptive BART level for NOx. See 40 C.F.R. Part 51, Appendix Y, Table 1. Yet Ecology has proposed a NOx emission limit for the Centralia plant of 0.24 lb/MMBtu 30-day rolling average with both units averaged together. This is well in excess of EPA's presumptive NOx BART limit for similar boiler and coal types. Indeed, the fact that Ecology's determination of NOx emission limits achievable with current NOx controls is 60% higher than EPA's presumptive BART limit for similar boiler and coal types dictates the addition of post-combustion controls for NOx removal in the BART analysis.

2. The NOx BART analysis improperly took into account costs of the "Flex Fuels" project.

Ecology's BART determination for the TransAlta Centralia Plant treats the "Flex Fuels" project as one of the BART controls to be evaluated for costs. While it is true that the change to Powder River Basin coal appears to have lowered the TransAlta Centralia Plant's NOx emission rate, Ecology should not have considered the coal switch as a NOx BART option to be evaluated, because it should have been considered part of the base case for NOx control at the TransAlta Centralia Plant. Further, the costs of switching to Powder River Basin coal at the TransAlta Centralia Plant should not have been considered by Ecology at all in its BART determination.

TransAlta did not switch to Powder River Basin coal to meet BART. Rather, a clear record of evidence shows that the company switched to Powder River Basin coal because the Centralia coal mine was at the end of its economic life. According to a November 27, 2006 statement from TransAlta:

> "After exhausting all alternatives, we have made the difficult but necessary decision to stop mining at Centralia," said Steve Snyder TransAlta President and Chief Executive Officer. "The maturity of the Centralia mine, its rapidly deteriorating mining conditions and escalating costs from excessive overburden have combined to make the mine uneconomic. In order to produce competitively priced electricity from our Centralia coal-fired plant, we have to meet the fuel requirements for our plant from a more predictable and economic source."

See November 27, 2006 TransAlta press release entitled: "TransAlta Stops Mine Operations At Centralia, Switches To Powder River Basin Coal, And Announces Intention To 'Write Down' Centralia Gas Fired Plant."[10] TransAlta's press release did not indicate that this decision was made to meet regional haze requirements or to lower air emissions. The press release makes clear that the decision was economic one made independently of the BART requirements.

Until TransAlta's November 2008 submittal supplementing its BART analysis for the TransAlta Centralia Plant, the company did not include any discussion of its switch to Powder River Basin coal as an emission reduction project to meet BART. Instead, its earlier BART submittals simply stated that the units burn Powder River Basin coal. For example, TransAlta's July 2008 BART submittal simply states under the heading "Coal Characteristics" that "[t]he main source of fuel burned at CPP is being transitioned to be exclusively western sub-bituminous

[10] Copy attached as Exhibit 6; see also http://www.transalta.com/newsroom/news-releases/2006-11-27/transalta-stops-mine-operations-centralia-switches-powder-river-ba.

coal from the Wyoming Powder River Basin (PRB) by 2013."[11] In fact, based on the November 27, 2006 TransAlta press release discussed above, TransAlta had already secured Powder River Basin coal contracts with Rio Tinto Energy America and Peabody Energy's subsidiary COALSALES, LLC., as well as rail transportation contracts with BNSF Railway Company, by November 2006.[12]

Moreover, the fact that TransAlta had to make numerous changes to the boiler to accommodate the coal cannot be considered in a cost determination for the BART analysis. The following describes the reasoning for the boiler changes at Centralia with the switch to Powder River Basin coal:

> The boiler changes will reduce the boiler susceptibility to ash deposition. The major individual pressure part changes include: (a) reheater replacement to maximize sootblower cleaning effectiveness on the tube assembly surface areas, and (b) additional low temperature superheater and economizer heat transfer surface area to result in a lower flue gas exit temperature. Miscellaneous safety and nonpressure boiler changes include: (a) twenty new retractable steam sootblowers and eight new steam wallblowers for each unit to help reduce the slagging and fouling in the boiler furnace and convective heat transfer surfaces; (b) hydrojets cleaning system to maintain heat transfer effectiveness inside the furnace and lower the flue exhaust gas temperature.

See TransAlta's November 2008 Supplement to the BART Analysis for the TransAlta Centralia Power Plant at 1.

Most, if not all, of TransAlta's equipment replacement at the TransAlta Centralia Plant was due to the company's economic decision to switch to Powder River Basin coal and for the need to extend the life of the boilers. The TransAlta Centralia Plant's boilers were commissioned in 1971 and 1972. The components of the boilers , in particular the reheater and the sootblowers, were at the end of their useful life. While these components may have been replaced in part to help the boilers better utilize the Powder River Basin coal, it is entirely inappropriate to include the costs of life-extension work as the cost of a BART "Flex Fuels" project. TransAlta and Ecology are misleading the public through their representations that TransAlta is spending a significant amount of money to reduce NOx. Rather, TransAlta made

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[11] *See* BART Analysis for Centralia Power Plant, prepared for TransAlta by CH2MHill, Revised July 2008, at ES-3.

[12] *See* November 27. 2006 TransAlta news release entitled: "TransAlta stops mine operations at Centralia, switches to Powder River Basin coal, and announces intention to 'write down' Centralia gas fired plant," Exhibit 6.

the business decisions to switch to Powder River Basin coal and to replace worn out components of the boiler in order to extend the life of the boilers another 20 years or more.

Ecology also misrepresents its rationale for the NOx decrease with the switch to Powder River Basin coal by stating that there would be less fuel burned because of the higher heat value of the Powder River Basin coal.[13] Given that the characteristics of Powder River Basin coal increase the heat rate of the boiler[14] (i.e., the amount of Btu heat input it takes to produce one kW-hr), the tons of coal burned will not likely decrease with the change to Powder River Basin coal. Depending on the amount of increased heat rate with Powder River Basin coal, the total amount of coal burned at the Centralia units could even increase above the amounts of Centralia mine coal burned in prior years.

Thus, for all of the above reasons, Ecology cannot properly conclude that the "Flex Fuels" project constitutes BART for NOx at Centralia. Although the switch to Powder River Basin coal at Centralia did reduce NOx emissions to some extent, the reductions come nowhere near to what EPA has identified as presumptive BART levels for this plant. Instead the burning of Powder River Basin coal at Centralia should simply be considered part of base case emissions in the BART evaluation. The "Flex Fuels" technology is the plant's current mode of operation, and has been since at least 2006 if not earlier, it fails to conform to presumptive BART limits and thus it does not meet the haze reduction requirements of the Clean Air Act or EPA regulation.

3. Ecology failed to consider state of the art combustion controls, including Selective NonCatalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR).

Neither Ecology nor TransAlta evaluated any upgrades to the Centralia units' low NOx burners that were installed between 2000-2002 or any additional combustion controls that could be used to reduce NOx at the boilers. Ecology has proposed a plantwide NOx BART emission limit with the unit's existing combustion controls of 0.24 lb/MMBtu (30-day average, both units averaged together). State-of-the-art combustion controls can achieve much lower NOx emissions with Powder River Basin coal.

For example, the W.A. Parish Unit 6 facility was retrofitted with DRB-4Z™ ultra-low NOx burners with interlaced overfire air in 2000, and has achieved post-retrofit NOx emissions

[13] *See* Washington Regional Haze Plan, Appendix L at 8.

[14] *Id.* at 7.

of 0.17 lb/MMBtu or lower.[15] The W.A. Parish facility was emitting NOx at a rate of 0.40 lb/MMBtu before the retrofit.[16]

In addition, at Plant Scherer Units 3 and 4 which burn 100% Powder River Basin coal and are approximately 900 MW in size each, modifications were made to add separated overfire air ports and openings to provide deeper staging capabilities and distance from the combustion zone. Unit 3 had baseline NOx emissions of 0.22 to 0.33 lb/MMBtu and its post change NOx emissions decreased to 0.12 to 0.14 lb/MMBtu.[17] Unit 4 achieved even lower NOx emissions – 0.10 to 0.13 lb/MMBtu.

As discussed in Dr. Sahu's November 4, 2009 comments on the TransAlta Preliminary BART Determination, another option to further reduce NOx is the use of neural net controls such as NueCo. See Exhibit 4, ¶ 14. Dr. Sahu also provided examples of several existing Powder River Basin coal fired electrical generating units achieving NOx emission rates lower than Centralia through the use of combustion controls. *Id.*, Tables 1-6.

With more effective combustion controls, the TransAlta Centralia Plant could likely at least reduce its NOx emissions to meet presumptive BART limit of 0.15 lb/MMBtu. Further, with lower levels of NOx emitted from the boiler, the size of SCR equipment can be reduced because less catalyst would be required to remove NOx, meaning lower capital and operational costs. Thus, Ecology should have required TransAlta to evaluate various combustion control techniques to reduce NOx emissions from the TransAlta Centralia Plant boilers and also should have required evaluation of those combustion control techniques along with SCR at the TransAlta Centralia Plant.

4. TransAlta appears to have overstated the cost of hot-side SCR installation at the TransAlta Centralia Plant units.

As discussed in the National Park Service's comment letters from November 2009 and June 2010, as well as in EPA's June 2010 comment letter to Ecology, the determination of costs for SCR installation at the TransAlta Centralia Plant appears to be greatly overstated in TransAlta's BART analysis.

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[15] See Bryk, S.A. et al., First Commercial Application of DRB-4Z™ Ultra Low NOx Coal-Fired Burner, presented to POWER-GEN International 2000, November 14-16, 2000, Orlando, FL. (Exhibit 7).

[16] *Id.*

[17] *See* Whitfield, T. et al., Comparison of NOx Emission Reductions with PRB and Bituminous Coal in 900 MW Tangentially Fired Boilers, presented to EPRI-DOE-EPA-AWMA Mega Symposium, May 19-22, 2003, at 6. (Exhibit 8).

a. Total capital costs are higher than reported by others.

Capital costs for pollution control equipment are commonly reported on a dollar per kilowatt of capacity basis. TransAlta estimated the capital costs for SCR installation at each TransAlta Centralia Plant unit to be $580,290,872.[18] At 702.5 MW each, this equates to $413/kW based on the net MW production of each unit. Yet five industry studies conducted between 2002 and 2007 have reported the installed unit capital cost of SCRs,[19] or the costs actually incurred by owners, expressed in dollars per kilowatt. These actual costs are lower than estimated for the TransAlta Centralia Plant, and they call TransAlta's estimates into serious question.

The first study evaluated the installed costs of more than 20 SCR retrofits from 1999 to 2001. The installed capital cost ranged from **$116 to $233/kW,** converted to 2008 dollars.[20] It should be noted that 2008 dollars are used in these comparisons because of the fact that theCH2MHill Centralia BART cost analysis are in 2008 dollars.[21] Costs are escalated through using the Chemical Engineering Plant Cost Index (CEPCI).

Similarly, the second survey of 40 installations at 24 stations reported a cost range of **$83 to $265/kW**, converted to 2008 dollars.[22] The third study, by the Electric Utility Cost Group, surveyed 72 units totaling 41 GW, which represents 39% of installed SCR systems in the U.S. The study reported a cost range of **$145/kW to $321/kW**, converted to 2008 dollars.[23] A fourth

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[18] *See* July 2008 TransAlta BART Analysis, Appendix A, Table entitled "Capital Costs for Both Units 1 and 2."

[19] J. Edward Cichanowicz, Current Capital Cost and Cost Effectiveness of Power Plant Emissions Control Technologies, June 2007. Exhibit 9.

[20] Bill Hoskins, Uniqueness of SCR Retrofits Translates into Broad Cost Variations, Power Engineering, May 2003. Exhibit 10. The reported range of $80 to $160/kW $123 - $246/kW was converted to 2008 dollars ($116 - $233/kW) using the ratio of CEPCI in 2008 to 2002: 575.4/395.6.

[21] *See* July 2008 TransAlta BART Analysis at ES-3.

[22] J. Edward Cichanowicz, Why are SCR Costs Still Rising?, Power, April 2004, Exhibit 11; Jerry Burkett, Readers Talk Back, Power, August 2004, Exhibit 12. The reported range of $56/kW - $185/kW was converted to 2008 dollars ($83 - $265/kw) using the ratio of CEPCI for 2008 to 1999 (575.4/.390.6) for lower end of the range and 2008 to 2003 (575.4/401.7) for upper end of range, based on Figure 3.

[23] M. Marano, Estimating SCR Installation Costs, Power, January/February 2006. Exhibit 13. The reported range of $100 - $221/kW was converted to 2008 dollars ($130 - $286/kW) using the ratio of CEPCI for 2008 to 2004: 575.4/444.2.
http://findarticles.com/p/articles/mi_qa5392/is_200602/ai_n21409717/print?tag=artBody;col1

study, presented in a course at PowerGen 2005, reported an upper bound range of **$197/kW to $221/kW**, converted to 2008 dollars.[24] A fifth summary study reports recent applications that either become operational in 2006 or were scheduled to start up in 2007 or 2008 cost in excess of $200/kW on a routine basis, with the highest one slated for startup in 2009 at $300/kW.[25]

Thus, the overall range for these industry studies is **$83/kW to $300/kW**. The upper end of this range is for highly complex retrofits with severe space constraints, such as Belews Creek, reported to cost **$290/kW**,[26] or Cinergy's Gibson Units 2-4. Gibson, a highly complex, space-constrained retrofit in which the SCR was built 230 feet above the power station using the largest crane in the world,[27] only cost $275/kW in 2008 dollars.[28]

Further, the Centralia SCR cost estimates are much higher than other recent estimates. Wisconsin Electric estimated the cost to retrofit SCR on Oak Creek Units 5-8 to be **$205/kW**[29] for a cold-side SCR. This cost was certified in July 2008 for construction by the Wisconsin Public Services Commission.[30] Wisconsin Power and Light estimated the cost to

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[24] PowerGen 2005, Selective Catalytic Reduction: From Planning to Operation, Competitive Power College, by Babcock Power, Inc. and LG&E Energy, December 2005, Exhibit 14. The reported range of $160 - $180/kW) was converted to 2008 dollars ($197 - $221/kW) using the ratio of CEPCI for 2008 to 2005 (575.4/468.2).

[25] J. Edward Cichanowicz, Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies, June 2007, pp. 28-29, Figure 7-1 (Exhibit 9).

[26] Steve Blankinship, SCR = Supremely Complex Retrofit, Power Engineering, November 2002, Exhibit 15. The unit cost: ($325,000,000/1,120,000 kW)(608.8/395.6) = $290/kW. http://pepei.pennnet.com/display_article/162367/6/ARTCL/none/none/1/SCR-=-Supremely-Complex-Retrofit/

[27] Standing on the Shoulder of Giants, Modern Power Systems, July 2002, Ex. 8.

[28] McIlvaine, NOx Market Update, August 2004, Exhibit 17. SCR was retrofit on Gibson Units 2-4 in 2002 and 2003 at $179/kW. Assuming 2002 dollars, this escalates to ($179/kW)(608.8/395.6) = $275.5/kW. http://www.mcilvainecompany.com/sampleupdates/NoxMarketUpdateSample.htm

[29] Wisconsin Electric Power Company's Application to Install Wet Flue Gas Desulfurization and Selective Catalytic Reduction Facilities and Associated Equipment on Oak Creek Power Plant Units 5, 6, 7 & 8 for Control of Sulfur Dioxide and Nitrogen Oxide Emissions, Appendix C, Emission Reduction Study, Volume 1, Addendum August 20, 2007. Unit cost = ($190,500,000/1,135,000 kW)(608.8/499.6) = $204.5 kW

[30] Certificate and Order, Application to Install Wet Flue Gas Desulfurization and Selective Catalytic Reduction Facilities and Associated Equipment on Oak Creek Power Plant Units 5, 6, 7

retrofit SCR on the 430-MW Edgewater Unit 5 to be **$324/kW** in January 2008.[31] The Edgewater project is pending before the Wisconsin Public Services Commission. Similarly, American Electric Power (AEP) estimated that the average capital cost to install SCRs to remove 85-93% of the NOx from many of its units was **$162/kW**.[32]

The data from these studies and examples indicates that CH2MHill's estimates of capital cost to retrofit SCR at Centralia **($413/kW**) are higher than actual installment costs for SCR retrofits, including very difficult retrofits (which TransAlta and Ecology claim without support, will be the case with the TransAlta Centralia Plant).

b. TransAlta and Ecology used an improper cost method.

There are several ways to estimate cost, depending upon intended use. Costs for BART analyses typically use the total annual cost approach.[33] The total annual cost approach has been used for BACT cost effectiveness analyses since about 1977. That approach estimates costs of various control options by calculating costs equalized annually over the life of the control. These costs are real or constant-dollar estimates in that the effect of inflation has been removed.

A standardized approach is used to assure a level playing field and consistency in estimating costs, as the significance of cost effectiveness values is determined by comparing the costs for a given project to costs at other similar sources. This method was selected by EPA because it determines the "economic" cost of air pollution control, i.e., the true cost to society, it is simple to use, and it allows comparison of alternative control systems with different economic lives. EPA has adopted this approach for BART determinations, with the BART guidance specifically recommending the use of the EPA Control Cost Manual, which uses the total annual cost approach.[34]

& 8 for Control of Sulfur Dioxide and Nitrogen Oxide Emissions, Case 6630-CE-299, July 10, 2008.

[31] Wisconsin Power & Light Co., Certificate of Authority Application, Edgewater Generating Station Unit 5 NOx Reduction Project, Project Description and Justification, November 2008, PSC Ref#: 105618, p. 11. Exhibit 18. The unit cost was calculated from the total project cost minus escalation divided by gross generating capacity or: ($153,944,000 - $14,695,000)/430 MW = $323.8/kW.

[32] AEP, 2008 Fact Book, 43rd Financial Conference, Phoenix, AZ, p. 94. Exhibit 19.

[33] This method is also called the equivalent uniform annual cost method. See 70 Fed. Reg. 39104, 39166 - 39167 (July 6, 2005) which notes the EPA Control Cost Manual should be used where possible. This Manual uses the total annual cost approach.

[34] 70 Fed. Reg. at 39166.

TransAlta did not use the total annual cost approach, and thus its cost effectiveness values are not relevant for purposes of determining cost effectiveness of the various BART options, especially SCR. Further, TransAlta included costs for items that are not to be addressed according to OAQPS's Control Cost Manual.[35]

For example, TransAlta included 8% sales tax in its SCR costs, improperly inflating its costs by $26.8 million.[36] Pollution control equipment is typically exempt from property and sales taxes, which are usually assumed to be zero.[37]

TransAlta also improperly included an additional 10% of the capital costs as "owner's costs."[38] Owner's costs are not included in EPA's Control Cost Manual. Owners do not manage and implement capital projects, but rather retain engineering firms, called the "owner's engineer," to perform these functions. Other owner activities would be part of its overhead. Cost factors used to estimate capital costs are ordinarily reported, and would include these costs. Further, these costs, if not directly part of the project, are outside of the battery limits of a control project and would be part of the owner's overhead. Thus, they are not usually included in cost effectiveness analyses as a separate additional cost.

In addition, TransAlta included a general category of "contingency" and added 15% to the capital costs of SCR at both units.[39] It is not clear what TransAlta intended to fall under this category, and it is questionable whether the inclusion of an addition 15% to the capital costs for unspecific "contingency" is legitimate. TransAlta also included a cost category of "margin" and further added 10% to the capital cost of the SCR installations.[40] TransAlta failed to explain or justify either cost category.

TransAlta further included the cost of lost generation at $20/MWhr and 42 days per unit for SCR installation in the capital cost.[41] This is not one of the allowable items included in the Control Cost Manual. Further, it appears that TransAlta assumed the units would operate at a

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[35] See CH2MHill March 11, 2010 Submittal to Ecology, Table A.

[36] *See* July 2008 Centralia BART Supplement, Appendix A.

[37] OAQPS Control Cost Manual, 2002, Section 4.2, p. 2-48 ("In many cases property taxes do not apply to capital improvements such as air pollution control equipment...")

[38] *See* July 2008 TransAlta BART Analysis, Appendix A, Table entitled "Capital Costs for Both Units 1 and 2."

[39] *Id.*

[40] *Id.*

[41] *Id.*

95% capacity factor during those 42 days. Outages are generally scheduled for slow periods when demand is at the lowest. Also, due to hourly fluctuations in demand, units ramp down during evening hours and rarely would operate at 95% capacity. In addition, it appears that the cost of replacement power did not consider the reduction in the TransAlta Centralia Plant's operating costs during the shutdown for SCR installation. TransAlta identified the capacity factor of the TransAlta Centralia Plant units as 78% of TransAlta's NOx BART cost analysis, plainly an overstatement.[42]

In addition, TransAlta included "Allowance for Funds During Construction" ("AFDUC.") in the capital costs [43] This is not allowed by the EPA Control Cost Manual.

It also appears that TransAlta only assumed a 15-year life of the SCRs in its cost analysis.[44] The default useful life for an SCR system in EPA's Control Cost Manual is 20 years.

The overall result of TransAlta's free use of inflated figures not allowed by the Control Cost Manual is a gross overstatement of the costs of SCR pollutant control technology. The National Park Service raised many of these issues, in addition to other problems with the TransAlta SCR cost analysis, in its November 20, 2009 letter and attachments and in its June 11, 2010 comment letter and attachments. We incorporate those comments by reference into these comments and also have included these comments as Exhibits 1 and 2 to this letter.

c. TransAlta underestimated the NOx emission reductions that can be obtained with SCR.

TransAlta assumed that the installation of SCR for the Centralia units would only achieve a NOx emission rate of 0.07 lb/MMBtu and a 72% NOx removal rate, a rate far below the pollutant reductions SCR can achieve.[45] However, 90% NOx removal with an SCR system is readily achievable. With the current NOx rates the Centralia units are achieving (i.e., lower than

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[42] *See* July 2008 TransAlta BART Analysis, Appendix A, Table entitled "Input Calculations for Both Units 1 and 2."

[43] *See* July 2008 TransAlta BART Analysis, Appendix A, Table entitled "Capital Costs for Both Units 1 and 2."

[44] *See* July 2008 TransAlta BART Analysis, Appendix A, Table entitled "Input Calculations for Both Units 1 and 2." TransAlta assumed a 15 year "Plant Economic Life."

[45] *Id.* Note that Ecology incorrectly states in its BART Determination for TransAlta that the company evaluated 95% NOx removal in its SCR cost analysis. *See* Ecology's BART Determination Document for TransAlta's Centralia Power Plant, revised April 2010, in Appendix L of Washington Regional Haze Plan, at 12.

0.24 lb/MMBtu) and a 90% effective SCR, the units could meet a NOx BART limit as low as 0.03 lb/MMBtu. Achieving these lower levels would represent an additional 57% reduction in NOx emissions that could readily be achieved with SCR, as compared to the meager emission reductions evaluated in TransAlta's SCR analysis.

A review of recent SCR retrofits at other power plants definitively proves that very high levels of NOx removal are being achieved by recent SCR retrofit installations. NOx emission rates less than 0.05 lb/MMBtu are routinely achieved, and NOx removal efficiencies are typically around 90%.[46] Permitting agencies have required lower NOx limits in recent BACT determinations, with many proposed and required BACT limits of 0.05-0.06 lb/MMBtu. For example, the Plant Washington PSD permit, issued in April 2010, requires that unit to meet a 0.03 lb/MMBtu annual average NOx limit as BACT.[47] The Desert Rock PSD permit includes a NOx BACT limit as low as 0.035 lb/MMBtu.[48]

According to TransAlta's calculations, NOx emissions from the two TransAlta Centralia Plant units combined would decrease from 10,910 tpy to 3,055 tpy, for a reduction of 7,855 tpy based on an assumed NOx rate of 0.07 lb/MMBtu and a 72% NOx control efficiency with SCR.[49] Had TransAlta more appropriately assumed a NOx rate of 0.03 lb/MMBtu, which reflects 87.5% removal from current NOx emission rates, the NOx emissions from the units in total would decrease to 1,309 tpy for a reduction of 9,601 tpy from TransAlta's assumed base case emission level of 10,910 tpy. This level would reflect approximately 1,900 additional tons of NOx removed above and beyond the levels assumed in TransAlta's cost analyses. Without adjusting any of the other flaws in TransAlta's SCR cost analysis described above and in the attached exhibits, it is apparent that when more accurate assumptions for NOx emission reductions are evaluated, the cost of SCR at both units would decrease to $7,436/ton of NOx removed (as compared to TransAlta's estimate of $8,205/ton of NOx removed). When the costs of SCR installation at the Centralia units are more appropriately determined, the cost per ton will be even lower.

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[46] *See* Erickson, Clayton A. et al., Selective Catalytic Reduction System Performance and Reliability Review, The 2006 MEGA Symposium, Paper # 121, Exhibit 20.

[47] A copy of the Plant Washington permit is included as Exhibit 21.

[48] The Desert Rock Energy Facility permit requires the facility to achieve, after a NOx optimization period, a NOx emission rate of 0.035 lb/MMBtu on a 365 day rolling average and an emission rate of 0.05 lb/MMBtu on a 30-day rolling average. Exhibit 22. *See also* the National Park Service spreadsheet on BACT limits for New PC Power Plants, Exhibit. 23.

[49] *See* July 2008 TransAlta BART Analysis, Appendix A, Table entitled "Input Calculations for Both Units 1 and 2."

The National Park Service re-calculated the cost effectiveness of SCR at Centralia based on the Control Cost Manual and an assumed NOx emission rate of 0.05 lb/MMBtu in its November 20, 2009 comments and June 11, 2010 comments to Ecology. Those costs are much lower than the inflated capital and annual costs provided by TransAlta. Specifically, the National Park Service's recalculated cost effectiveness of SCR installation at both Centralia units of $5,622./ton which they found it to be a reasonable cost based on the cost of BART installation at other coal-fired electrical generating units.[50]

Ecology must require that the BART analysis of SCR at the Centralia units be based on achievable NOx emission rates, which would be lower than the 0.07 lb/MMBtu emission rate assumed by TransAlta. NOx emission rates of 0.03 lb/MMBtu should be achievable at the Centralia units given the current NOx emission rate, which is below 0.24 lb/MMBtu. The ceiling for the NOx BART limit evaluated should be no higher than 0.05 lb/MMBtu, which should be readily achievable with SCR at the Centralia units.

5. Neither TransAlta nor Ecology evaluated the cost-effectiveness of SCR in a low dust or tail end location.

TransAlta's NOx BART analysis raised issues with the tight space and duct arrangement for installation of SCR units at Centralia. Thus, TransAlta assessed the arrangement of the SCRs physically on top of the existing electrostatic precipitators, which they claimed "exponentially increased the capital costs."[51] Alternative arrangements include: an outboard arrangement; a low-dust SCR (located after the particulate control device); and a tail-end SCR located at the tail end, following all pollution control devices. These latter alternative arrangements are attractive as the SCR is located downstream of the air preheater, thus avoiding the space-constrained area between the boiler outlet and the inlet to the air preheater. Subsets of these alternatives include ducting together two or more units. There is no evidence that any alternative arrangements were considered by Ecology or TransAlta.

Only a high-dust SCR was evaluated for costs. However, retrofitting of a low- dust or tail-end SCR may be a more cost-effective retrofit—especially if combined with upgraded particulate matter controls for these units. Recently, for example, Wisconsin Energies decided it was more cost effective to retrofit Oak Creek Units 5-8 with low dust/tail-end SCRs, rather than

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[50] *See* June 11, 2010 National Park Service Followup Comments on Washington Department of Ecology's (Ecology's) Proposed Best Available Retrofit Technology (BART) Determination for TransAlta Centralia Generation (Exhibit 1) at 12. *See also* the National Park Service spreadsheet of NOx BART Limits and Costs (Exhibit 24).

[51] *See* July 2008 TransAlta BART Analysis at 3-9.

the more traditional high-dust SCRs.[52] Tail-end SCR units can be smaller than high dust units, have longer catalyst life, and can use less expensive catalysts.[53]

Ecology's BART analysis for Centralia is deficient without a cost analysis of alternative SCR locations.

6. Neither TransAlta nor Ecology adequately evaluated the other environmental benefits of SCR installation at the TransAlta Centralia Plant units.

As described above, if TransAlta were to install SCR systems along with combustion controls at the Centralia units, it could reduce NOx emissions by 90%. Not only would such installation improve visibility in the region's Class I areas, it would also likely improve the region's ozone pollution (i.e. O3) due to the fact that NOx is a precursor to ozone. One monitor in King County, to the north of Centralia, shows that emissions are violating the 2008 ozone NAAQS of 0.075 ppm, and Ecology has indicated they will recommend that area for nonattainment designation.[54] Further, data provided with EPA's January 2010 proposed revisions to the ozone NAAQS, which EPA has proposed to lower from 0.075 ppm to 0.060 to 0.070 ppm (8-hour average) (see 75 Fed. Reg. 2938, January 19, 2010), indicates that King County, Pierce County, and Thurston County could be in nonattainment for ozone depending on the level of the final ozone NAAQS that EPA adopts.[55] Reductions in NOx, which are achievable at the Centralia Plant with SCR, would likely help address those counties' ozone problems. Since vegetation damage has been found to occur even where ozone concentrations are below the ozone NAAQS, greater reductions in NOx emissions from the Centralia Plant, as would be obtained by the installation of SCR controls, could also benefit the vegetation of the region's Class I areas.

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[52] See August 24, 2007 letter from Wisconsin Energies to the Public Service Commission regarding the Oak Creek Power Plant, Appendix C August 20, 2007 Addendum Emission Reduction Study, and Appendix C NOx/SO2 Emission Reduction Study. These document are all included as Exhibit 25 to this letter.

[53] See January 2009 FGD and DeNOx Newsletter. Exhibit 26.

[54] *See* March 5, 2009 letter from Ecology to EPA, available at http://www.epa.gov/ozonedesignations/2008standards/rec/letters/10_WA_rec.pdf.

[55] *See* EPA Map Entitled "Counties with Monitors Violating Primary 8-hour Ground-level Ozone Standards 0.060 – 0.070 parts per million," available at http://www.epa.gov/air/ozonepollution/pdfs/20100104maps.pdf.

In addition, nitrogen deposition is also a significant environmental issue in the region. The significant adverse impacts of nitrogen deposition, which are caused by wet and dry deposition of nitrates derived from NOx emissions, on ecological systems is well known. Critical loads (*i.e.*, the amount of nitrogen deposition that an ecosystem can tolerate, above which the system become adversely impacted) are likely to soon be formally used to inform policy developments (*e.g.*, NADP-CLAD Meeting, Pensacola, FL Spring 2009). Further, National Park Service data shows significant concerns with nitrogen deposition in Mt. Rainier National Park, the closest Class I area to the TransAlta Centralia Plant, as well as in Olympic and North Cascades National Parks.[56] Thus, the potential to reduce nitrogen deposition-forming emissions is another compelling reason for requiring installation of the top NOx control measures as BART at the TransAlta Centralia Plant.

Reductions in NOx emissions achievable with SCR would also result in reduced fine particulate emissions. The use of ammonia injection before the electrostatic precipitator ("ESP") has also been shown to reduce sulfate formation by high levels, which would further benefit visibility as well as sulfate deposition and fine particulate concentrations.[57]

Finally, the use of SCR controls helps to oxidize the mercury emitted so it is more readily captured in a particulate control device.[58] SCR catalysts can act to oxidize elemental mercury (*e.g.*, to $HgCl_2$) making it easier to capture downstream in wet FGD systems or particulate matter collection devices. Currently, several industry improvements in SCR technology are being developed that would enhance mercury oxidation across an SCR catalyst for all coal types.[59] SCR would help TransAlta do much better mercury removal than the anemic 50% reduction goals that it has agree to with the state.

In summary, if the TransAlta Centralia Plant were subject to the best control technology for NOx reductions, *i.e.*, SCR (along with Powder River Basin coal and current or upgraded combustion controls), as compared to continuing with the current status quo at the TransAtla

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[56] *See* National Park Service's Air Quality in National Parks, 2008 Annual Performance and Progress Report at 10, available at http://www.nature.nps.gov/air/Pubs/pdf/AQ_Trends_In_Parks_2008_Final_Web.pdf

[57] R.K.Srivastava et al., Emissions of Sulfur-Trioxide from Coal-Fired Power Plants, *J. Air & Waste Manage. Assoc.*, 54: 750-762 at 758-759, June 2004, Exhibit 27.

[58] *See* EPA's Performance and Cost of Mercury and MultiPollutant Emission Control Technology Applications on Electric Utility Boilers, EPA-600/R-03-110, October, 2003, at 5, 9-15. Exhibit 28.

[59] June 29, 2004 letter from ICAC to EPA, pp. 15-17. Exhibit 29.

Plant, significant environmental benefits that would be obtained. Those benefits must be considered by Ecology in determining BART for NOx at the TransAlta Centralia Plant.

7. Ecology must determine the visibility benefits of the SCR plus Flex Fuels BART option.

Neither TransAlta nor Ecology modeled the visibility impacts of the Flex Fuels project (i.e., the lower SO2 emissions due to the lower sulfur coal) in addition to SCR at the TransAlta Centralia Plant units. Instead, TransAlta only modeled the visibility impacts based on a NOx emission rate of 0.07 lb/MMBtu with SCR, but keeping SO2 emissions at the level prior to the Flex Fuels change.[60] This is factually unsupportable. Rather than perform the required visibility analysis for this significant BART option, Ecology simply offered a qualitative statement that "…there would be additional visibility improvements were PRB coal continued to be used by the facility and SCR added."[61] Ecology has not fully evaluated the SCR option without such a visibility analysis, which is mandated by the Clean Air Act and EPA's regional haze regulations. *See* 40 C.F.R. §§51.301 (definition of "best available retrofit technology," 51.308(e)(1)(ii), Appendix Y, Section F.2.(c) and under Step 5; *see also* 42 U.S.C. §7492(g)).

Ecology's assumption that TransAlta would revert to burning Centralia mine coal if SCR was installed is faulty and unsupported. As Ecology has indicated in its BART analysis, he units have been physically modified to more efficiently burn Powder River Basin coal. The company has agreements in place to obtain coal from Powder River Basin mines. Such coal supply contracts cannot be readily cancelled. Thus, TransAlta cannot readily revert to burning Centralia coal.

EPA recently informed Ecology that a complete modeling analysis of the visibility impacts due to SCR along with use of Powder River Basin coal at the Centralia units is necessary in order for the Centralia BART analysis to be considered complete.[62] Yet, Ecology has not required or performed this modeling.

The modeling that TransAlta did for Flex Fuels plus SNCR is not adequate to represent the visibility assessment for Flex Fuels plus SCR. TransAlta only assumed a 25% reduction in NOx emissions with SNCR beyond the NOx levels achieved with Flex Fuels. SCR can achieve 90% NOx removal, which would mean 3-4 times more NOx removed or an additional 8,000-

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[60] *See* BART Determination Support Document for TransAlta Centralia Generation, LLC, Power Plant, Washington Department of Ecology, Revised April 2010, in Appendix L of Proposed Washington Regional Haze Plan, at 17.

[61] *Id.*

[62] *See* June 30, 2010 letter from EPA to Ecology, Exhibit 5.

9,0000 tpy of NOx removed with SCR plus Flex Fuels as compared to SNCR plus Flex Fuels. Such a big decrease in NOx emissions would have a significant impact on visibility.[63]

Ecology cannot adopt its regional haze plan and finalize BART requirements for the TransAlta Centralia Plant without requiring this analysis of the visibility benefits of Flex Fuels plus SCR at both the TransAlta Centralia Plant units.

For all of the above reasons, the BART analysis for the TransAlta Centralia Plant is flawed and incomplete. The Flex Fuels project, in which TransAlta switched to burning Powder River Basin coal for economic reasons, does not constitute BART because it essentially reflects the status quo for Centralia. Given that the Washington Regional Haze SIP does not show that improvements in visibility will be on track to meet the national visibility goal by 2064 at most of the state's Class I areas, the BART determination for the Centralia Power Plant (the largest source of regional haze pollution in the state) must reflect the best system of continuous emission reduction for NOx. TransAlta greatly overestimated the costs for SCR installation and failed to follow EPA requirements for conducting such cost analyses in a BART review. Further, TransAlta underestimated the NOx reductions achievable with SCR and the use of Powder River Basin coal.

The National Park Service analyzed costs of SCR at Centralia in its November 20, 2009 and its June 11, 2010 comments to Ecology using conservative assumptions and more reasonable emission rates, but following EPA's Control Cost Manual. The costs calculated by National Park Service are much lower than those provided by TransAlta. Specifically, the National Park Service's recalculated cost effectiveness of SCR installation at both Centralia units of $5,622./ton which they found it to be a reasonable cost based on the cost of BART installation at other coal-fired electrical generating units.[64]

Ecology has failed to require a modeling analysis that would show the benefits to regional haze in the state's national parks and wilderness areas due to installation of SCR along with the burning of Powder River Basin coal at the TransAlta Centralia Plant units. With that analysis, Ecology could then assess BART in terms of $/deciview of improvement, which would be a fair way to compare BART costs among different sources. Based on the available

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[63] *See* BART Determination Support Document for TransAlta Centralia Generation, LLC, Power Plant, Washington Department of Ecology, Revised April 2010, in Appendix L of Proposed Washington Regional Haze Plan, at 16.

[64] *See* June 11, 2010 National Park Service Followup Comments on Washington Department of Ecology's (Ecology's) Proposed Best Available Retrofit Technology (BART) Determination for TransAlta Centralia Generation (Exhibit 1) at 12.

information, Conservation Organizations submit that such an analysis would further demonstrate that SCR is the appropriate requirement for BART.

B. BART for Tesoro Refining.

The Tesoro Refinery in Anacortes, WA had the highest visibility impacts to Olympic National Park and in North Cascades National Park.[65] Ecology determined that the current emission controls and emission limitations for the Tesoro Refinery, with the exception of one heater, which will obtain new low NOx burners, constitute BART.[66] Ecology's reasoning for not requiring NOx BART installation at any other unit at the Tesoro Refinery was "[d]ue to time needed for the design approval process and the major maintenance cycle at the refinery…."[67] Specifically, for the CO Boiler 2 (F-304) and the catalytic reformer heaters F-6650 through F6653, Ecology determined that it was not cost effective for these units to install new ultra low NOx burners by the BART compliance date (5 years from the date EPA approves the regional haze plan).[68] Ecology determined it would be cost effective for these units to install new low NOx burners by the next scheduled turnaround in 2017.[69] These units are also scheduled for turnaround in 2012. Ecology did not explain why new low NOx burners could not be installed on these units in 2012.

Tesoro has had plenty of notice that BART would be required, and that compliance would be required as expeditiously as practicable, and no later than five years from the date EPA approves the regional haze SIP. EPA promulgated the regional haze rules, including the BART requirements, over 10 years ago. Tesoro first submitted its BART analysis to Ecology in February 2008, 4 years before the 2012 turnaround. Thus, both Tesoro and Ecology could have planned for the installation of low NOx burners at these units in 2012, if not by 2015. In addition, at this point, the BART compliance deadline could reasonably extend to the middle of 2016 if not later because EPA will not likely approve the Tesoro BART requirements any earlier than June of 2011.

In fact, Ecology has simply decided to give Tesoro an exemption from NOx BART, rather than require that Tesoro either change its turnaround schedule for these units (bumping it up by 6 months to year) or require Tesoro to install low NOx burners by 2012. Given that the

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[65] *Id.* at 11-11.

[66] *See* Proposed Washington Regional Haze plan, Chapter 11 at 11-15.

[67] *Id.* at 11-16.

[68] *See* Ecology's BART Support Document, Tesoro Refining and Marketing Company, Revised February 22, 2010, in Appendix L of Proposed Washington Regional Haze Plan, at 38.

[69] *Id.* at 39.

Washington Regional Haze plan utterly fails to meet reasonable progress milestones, showing visibility actually *degrading* in the North Cascades National Park in 2018[70] and estimating that it will take 323 years for Olympic National Park to reach the national visibility goal[71], Ecology cannot justify allowing the refinery to avoid having to meet BART for NOx simply because the compliance deadline does not fit the refinery's preferred maintenance cycle. At a minimum, Ecology should require Tesoro to install new low NOx burners in 2017 during the normal turnaround time for the CO boiler 2 (F-304) and the F6650 to F6653 heaters. Yet, Ecology has not specified *any* reasonable progress requirements for this (or any other) facility. There is simply no excuse for Ecology's failure to require the installation of cost-effective NOx controls at these units as part of its regional haze plan.

Further, Ecology did not require a complete evaluation of BART for SO2 emitted from the Tesoro refinery. Tesoro identified as a control option plantwide SO2 control by removing sulfur from refinery gas via a refinery gas sulfur removal system (which has already been installed at the facility) and recovering the sulfur via a sulfur recovery unit. The sulfur recovery unit currently used by the refinery is operating at capacity, so a new unit would need to be installed. Ecology did not require this control method to meet SO2 emissions. Ecology did not adequately explain the basis for rejecting the SO2 BART controls. If it rejected this control due to the costs, such rejection is not supported. The cost of the sulfur recovery unit evaluated for Tesoro was for a 50 ton per day unit. The BART analysis indicated between 395 to 451 tons per year of SO2 would be reduced from the facility.[72] A 50 ton-per-day sulfur recovery unit can recover 50 tons of sulfur per day, which would equate to a reduction of about 97 tons of SO2 removed *per day.* Yet, the BART analysis inexplicably indicates that 395 to 451 tons of SO2 would be removed *per year*. Thus, the sulfur recovery unit assessed is greatly oversized for the SO2 removal it has to obtain, and a larger sulfur recovery unit will have a higher capital cost than a smaller sulfur recovery unit. Also, based on the annual costs of $6,359,500/year,[73]stated for the assumed $58 million capital cost of a sulfur recovery unit, it appears the annual costs relied a higher interest rate than 7% and/or a shorter life of the sulfur recovery unit than 30 years.[74]

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[70] Washington Proposed Regional Haze Plan, Chapter 9 at 9-8

[71] *Id.* at 9-7.

[72] *See* Ecology's BART Support Document, Tesoro Refining and Marketing Company, Revised February 22, 2010, in Appendix L of Proposed Washington Regional Haze Plan, at 16.

[73] This was determined by multiplying the $14,100/ton cost by the 451 tons of SO2 reduced, as provided in Ecology's BART Support Document for Tesoro at 16.

[74] To annualize capital costs, the capital costs are multiplied by a Cost Recovery Factor. The Cost Recovery Factor is given by the following equation: CRF - $[i(1+i)^n]/[(1+i)^n -1]$

In addition, not only was the cost overestimated due to the size of the Sulfur Recovery Unit, but the stated cost even of a 50 ton-per-day unit seems high. In 2005, the capital cost for a 50 ton-per-day unit was approximately $15 million dollars.[75] That would be $16.5 million in 2008 dollars, which is significantly lower than the $58 million stated as the cost in the Tesoro BART analysis. A 10 ton-per-day sulfur recovery unit, which would still be oversized for the required SO2 removal, would cost only $7.8 million in 2005 dollars.[76] This would be $8.6 million in 2008 dollars. Applying a cost recovery factor assuming 7% interest and 30-year life equates to an annualized cost of $687,982 per year. If 451 tons of SO2 are removed per year, this equates to $1,525/ton of SO2 removed. This should be considered to be a reasonable cost of SO2 removal.

In summary, the NOx and SO2 BART determinations for the Tesoro Refinery are inadequate. As with the TransAlta Centralia Plant, Ecology has determined that the status quo constitutes BART, with the exception of one heater that will be required to install low NOx burners as BART. No additional SO2 controls have been proposed as BART, nor to meet reasonable progress requirements. Given that the SIP does not provide for reasonable progress toward the national visibility goal, it is imperative that Ecology require installation of cost effective pollution controls as BART, or at the minimum, to meet reasonable progress requirements.

C. BART for Alcoa-Wenatchee Works.

Ecology has proposed to find that the Alcoa plant in Wenatchee is not subject to BART because it does not significantly impact visibility in any Class I area. Unfortunately, Ecology's determination is based on a non-guideline model. EPA has informed Ecology that it must first obtain EPA approval for use of this non-guideline model.[77] The National Park Service "strongly disagree[s]" with the use of an ultra-fine modeling grid to exempt Alcoa Wenatchee from

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where i is the interest rate and n is the life of the pollution control equipment. In essence, annualization establishes an annual payment sufficient to finance the capital investment for its entire life. *See* EPA Control Cost Manual, January 2002, Section 1, p. 2-21. For the Sulfur Recovery Unit at Tesoro, assuming 7% interest and a 30 year life, the annualized costs should be $4,640,000.

[75] *See* Gary, James H. et al., Petroleum Refining, Technology and Economics, 5th Edition, 2007, Figure 13.8 at 288. An excerpt from this book with Figure 13.8 is included as Exhibit 30 to this letter.

[76] *Id.*

[77] *See* June 30, 2010 Letter from EPA to Ecology at 1 (Exhibit 5).

BART.[78] Until such approval for the use of a non-guideline model is obtained from EPA, Ecology cannot assume that the Alcoa Wenatchee Works plant is exempt from BART. Ecology should have evaluated BART options for this facility.

II. THE HAZE PLAN MUST PROVIDE FOR REASONABLE PROGRESS.

The Haze Plan must also provide a long-term strategy for achieving reasonable progress toward meeting natural visibility conditions at mandatory Class I areas by 2064. 40 C.F.R. § 51.308(d)(1)(i)(B). If a state's reasonable progress goals do not anticipate restoring visibility to natural conditions by 2064 the state must demonstrate why the goal of attaining natural conditions by the established date is unreasonable. 40 C.F.R. § 51.308(d)(1)(ii). The Haze Plan must provide for improved visibility on the most impaired days and ensure no degradation in visibility for the least impaired days. 40 C.F.R. § 51.308(d)(1)(i)(B). The long-term strategy is typically a 10-15 year plan containing enforceable measures designed to meet regional progress goals. In developing its plan, the State must document the technical basis for the SIP, including monitoring data, modeling, and emission information, including the baseline emission inventory upon which its strategies are based. 40 C.F.R. § 51.308(d)(3)(iii).

In developing its long-term strategy, a state must consider all anthropogenic sources of visibility impairment and evaluate different emission reduction strategies beyond those prescribed by the BART provisions. 40 C.F.R. §51.308(d). A state should consider "major and minor stationary sources, mobile sources and area sources." *Id.* At a minimum, a state must consider the following elements:

> (A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
> (B) Measures to mitigate the impacts of construction activities;
> (C) Emissions limitations and schedules for compliance to achieve the reasonable progress goal;
> (D) Source retirement and replacement schedules;
> (E) Smoke management techniques for agriculture and forestry management purposes including plans as currently exist within the State for these purposes;
> (F) Enforceability of emission limitations and control measures; and
> (G) The anticipated net effect on visibility due to projected changes in point, area, and mobile emissions over the period addressed by the long-term strategy.

40 C.F.R. 51.208(d)(3)(v)(A)-(G).

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[78] *See* June 11, 2010 Letter from NPS to Ecology, Attachment Entitled "Washington Draft State Implementation Plan for Regional Haze at 5 (Exhibit 1).

In addition to its failure to adequately assess and require BART, including SCR for the TransAlta Centralia Plant, Washington has not required any source emission reductions or source retirements other than its inadequate, proposed BART requirements to meet reasonable progress requirements. Regardless of its failure to properly assess BART of impacts that other sources outside of Washington may have on regional haze in Washington's Class I areas, Washington has a responsibility under the federal regional haze requirements to reduce haze-causing emissions from its own sources of air emissions in order to fulfill its legal duty to meet the reasonable progress goals. Under the Long Term Strategy regulations, Washington is required to demonstrate that "it has included in its implementation plan *all* measures necessary to obtain its share of the emission reductions needed to meet the progress goals for the area" even when sources from outside the state contribute to visibility impairment in the State's Class I areas. 40 C.F.R. § 51.308(d)(3)(ii) (emphasis added). Further, Washington has a responsibility to reduce emissions from Washington sources that are reasonably anticipated to impact visibility in other states' Class I areas. Idaho and Oregon are such states. Therefore, Washington must impose SCR on the TransAlta Centralia Plant and BART on Tesoro and Alcoa Wenatchee in order to meets is obligations on reasonable progress in Class I areas.

CONCLUSION

For all of the reasons given above, and as supported in the attached exhibits, the proposed Washington regional haze state implementation plan is technically and legally deficient. Conservation Groups urge Ecology to re-evaluate BART for the Centralia Power Plant and for the Tesoro Refinery, to require additional emission reductions beyond what these facilities are currently emitting. As the modeling for Washington's Class I areas shows, there is no way the state can show reasonable progress toward the national visibility goal without the adoption of additional emission reduction measures.

Thank you for considering these comments.

Sincerely,

Janette K. Brimmer
Earthjustice
Counsel for Conservation Organizations

Attachments
cc: Keith Rose, EPA Region 10

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-106:
Shutdown Memorandum of Agreement

MEMORANDUM OF AGREEMENT

This Memorandum of Agreement (this "MOA") is entered into as of December 23, 2011, effective as of the Effective Date (as defined below), by and between the State of Washington, acting through and by Governor Christine Gregoire (the "State"), and TransAlta Centralia Generation LLC, a Washington limited liability company (the "Company" and, together with the State, each a "Party" and together, the "Parties").

RECITALS

A. The Company owns and operates a 1,340 megawatt coal-fired baseload electric generating facility in Centralia, Washington (the "Facility"), which utilizes two coal-fired generating boilers (each, a "Boiler" and together, the "Boilers").

B. Pursuant to RCW 80.80.100, the Governor, on behalf of the State, has been directed to enter into a memorandum of agreement with owners of certain coal-fired facilities in the State of Washington, including the Facility.

C. In order to implement RCW 80.80.100, the Parties desire to memorialize their understanding with respect to certain emissions reductions, installation of selective noncatalytic reduction pollution control technology ("SNCR"), the provision of financial assistance with respect to economic development and the funding of certain energy technologies and certain other matters, in each case subject to the terms and conditions set forth herein.

D. In exchange for the benefits of entering into an MOA with the State pursuant to RCW 80.80.100, the Company will, among other things, (1) at the direction of the State, make certain payments into independent accounts to be held at an appropriate financial institution (the "Account Agent"), an appropriate financial institution within the meaning of RCW 80.80.100, for the provision of financial assistance as set forth in Section 3 of this MOA, (2) pay Interest Tax Liability (as defined in Section 3(b) below), (3) establish, with the State, boards to approve grants from such independent accounts, (4) install SNCR technology and (5) permanently cease power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives, in each case pursuant to the terms and subject to the conditions of this MOA.

E. In exchange for the benefits of entering into an MOA with the Company pursuant to RCW 80.80.100, the State will, among other things, (1) establish air emission requirements based on the use of SNCR, (2) establish, with the Company, boards to approve grants from such independent accounts, (3) recognize investments by the Company in emissions reductions and confirm that based upon early retirement of the Boilers, Facility power is a climate responsible transition product that will substantially contribute to the state meeting its climate change policies and achieve the greenhouse gas reductions in RCW 70.235.020(1)(a),

(4) confirm that Facility power is a product that meets the greenhouse gas emissions performance standards of the State, (5) permit entry into long-term power contracts for the sale of electricity, (6) provide certainty regarding environmental requirements that affect power generation operations, and (7) provide certainty regarding sales and use tax exemptions, in each case pursuant to the terms and subject to the conditions of this MOA.

NOW, THEREFORE, in consideration of the mutual benefits to be derived herefrom, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties agree as follows:

AGREEMENT

1. Effective Date; Term. This MOA shall be effective on April 1, 2012 (the "Effective Date"). Unless terminated pursuant to the terms of Section 8, this MOA shall terminate upon the later to occur of (i) December 31, 2025, or (ii) the disbursement of all amounts deposited in the Accounts pursuant to the terms of the Account Agreement and Section 4.

2. Incorporation by Reference. The provisions of RCW 80.80.040, RCW 80.80.060 and RCW 80.80.070, in each case as in effect on July 22, 2011, are hereby incorporated herein by reference.

3. Company Contribution of Financial Assistance.

(a) Beginning January 1, 2012 and ending December 31, 2023, or until the full amounts set forth in Section 3(b) have been provided, the Company shall make annual payments by wire transfer of immediately available funds to the following independent accounts maintained by the Account Agent on behalf of the Company in the following amounts (in each case, less Interest Tax Liability incurred with respect to amounts in such accounts during the previous year pursuant to the terms of Section 3(b)):

(i) $833,333.33 annually to an account established to fund energy efficiency and weatherization for the residents, employees, businesses, non-profit organizations and local governments within Lewis County and South Thurston County, Washington, from which Grants (as defined herein) are to be made pursuant to the terms of the Account Agreement and Section 4 (the "Weatherization Fund"), of which an aggregate amount of up to $1,000,000, calculated over the life of the Weatherization Fund, shall be allocated to fund residential energy efficiency and weatherization measures for low-income and moderate-income residents of Lewis County and South Thurston County, Washington;

(ii) $1,666,666.67 annually to an account established to fund education, retraining, economic development, and community enhancement, from which Grants are to be made pursuant to the terms of the Account Agreement and Section 4 (the "Economic and Community Development Fund"), of which an

aggregate amount of at least $5,000,000, calculated over the life of the Economic and Community Development Fund, shall be allocated to fund education, retraining and economic development specifically targeting the needs of workers displaced from the Facility; and

(iii) $2,083,000.33 annually to an account established to fund energy technologies with the potential to create considerable energy, air quality, haze or other environmental benefits located in or otherwise to the benefit of the State of Washington, from which Grants are to be made pursuant to the terms of the Account Agreement and Section 4 (the "Energy Technology Fund" and, together with the Weatherization Fund and the Economic and Community Development Fund, the "Accounts").

The Company shall pay such amounts for each calendar year on or before December 31 of such calendar year. Pursuant to the terms of Section 4, grants of funds from the Accounts (each, a "Grant") shall be made in accordance with the purpose for each such Account as set forth in Sections 3(a)(i) through 3(a)(iii) ("Proper Grant Purposes").

(b) In connection with the execution of this MOA and the transactions contemplated hereby, and prior to the date that any amounts are deposited in the Accounts pursuant to Section 3(a), the Company shall execute an agreement with the Account Agent governing the terms of the Accounts and disbursements therefrom (the "Account Agreement"), but only after the Company has provided the Office of the Governor the opportunity to review the Account Agreement and the Office of the Governor consents to the terms of the Account Agreement. The terms of the Account Agreement shall be consistent with and in furtherance of the terms of this MOA and RCW 80.80.100, and shall include a requirement that the disbursement of Grants from the Accounts be conditioned upon the Account Agent's receipt of a written resolution of a Supermajority of the applicable Grant Review Board in accordance with Section 4(h), a requirement that funds be invested in low-risk investment alternatives designed to preserve principal, the assumption by the Company of all Income Tax Liability associated with the Accounts in accordance with Section 3(c) and a term of years coextensive with this MOA.

(c) The Company shall assume the obligation to pay taxes on interest and gains on all funds deposited in the Accounts (the "Interest Tax Liability"). Notwithstanding anything to the contrary in this Section 3, the amount of Interest Tax Liability incurred by the Company shall reduce the amount of payments to the applicable Account required by Sections 3(a)(i) through 3(a)(iii), as a result of which (i) the maximum contribution to the Weatherization Fund by the Company under this MOA shall not exceed an amount equal to $10,000,000 minus any Interest Tax Liability incurred with respect to funds in the Weatherization Fund, (ii) the maximum contribution to the Economic and Community Development Fund by the Company under this MOA shall not exceed an amount equal to $20,000,000 minus any Interest Tax Liability incurred with respect to funds in the Economic and Community Development Fund, and (iii) the maximum contribution to the Energy Technology Fund by the Company under this MOA shall not exceed an amount equal to $25,000,000 minus any Interest Tax Liability incurred with respect to funds in the Energy Technology Fund. All interest and gains earned on funds deposited in any Account shall remain in such Account and shall constitute additional funds

from which Grants may be made, with no corresponding offset or deduction other than as set forth in the immediately preceding sentence.

(d) All fees and expenses of the Account Agent payable pursuant to the Account Agreement or otherwise shall be paid out of funds in the Accounts. Other than payments made from the Account as set forth in this Section 3, neither Party shall have any liability for fees or expenses of the Account Agent with respect to the Accounts under this MOA, the Account Agreement or otherwise.

4. Grant Review Board; Authorization of Expenditures

(a) No later than July 1, 2012, the Parties agree to establish three boards (together, the "Grant Review Boards"), each of which will have the authority to approve Grants from one Account in accordance with Proper Grant Purposes and the provisions of this Section 4.

(b) Initial Composition of Grant Review Boards. The Grant Review Boards shall initially consist of members (the "Board Members") as set forth below; provided that each Board Member shall have legal, financial, energy or other experience relevant to his or her service on such Grant Review Board, as determined by the Party authorized to designate such Board Member pursuant to this Section 4(b) in such Party's reasonable discretion:

(i) The Grant Review Board with the authority to approve Grants from the Weatherization Fund (the "Weatherization Board") shall consist of the following Board Members:

(A) one member selected by the Lewis County Economic Development Council;

(B) one member selected by the United Way of Lewis County;

(C) one elected commissioner of the Lewis County Public Utility District, selected by the District;

(D) one member selected by Centralia City Light;

(E) one member selected by the NW Energy Coalition;

(F) one employee of the Company selected by the Company; and

(G) five representatives of the Company selected by the Company.

(ii) The Grant Review Board with the authority to approve Grants from the Economic and Community Development Fund (the "Economic and Community Development Board") shall consist of the following Board Members:

(A) one member selected by the Lewis County Economic Development Council;

(B) one local elected official from Lewis County, Washington, selected by the Lewis County Commissioners;

(C) one member selected by the Centralia Chehalis Chamber of Commerce;

(D) one member selected by the Thurston- Lewis- Mason Central Labor Council;

(E) one employee of the Company selected by the Company; and

(F) four representatives of the Company selected by the Company.

(iii) The Grant Review Board with the authority to approve Grants from the Energy Technology Fund (the "Energy Technology Board") shall consist of the following Board Members:

(A) one member selected by the Lewis County Economic Development Council;

(B) one local elected official from Lewis County, Washington, selected by the Lewis County Commissioners;

(C) one member selected by the Centralia Chehalis Chamber of Commerce;

(D) one member selected by Climate Solutions;

(E) one member selected by the Thurston- Lewis- Mason Central Labor Council;

(F) one member selected by Innovate Washington;

(G) one member selected by the Southwest Clean Air Agency;

(H) two employees of the Company, selected by the Company; and

(I) six representatives of the Company selected by the Company.

(c) At any time following the third anniversary of the Effective Date, the Company and the office of the Governor of the State may jointly agree to substitute any entity

authorized to designate a Board Member pursuant to Section 4(b) with another entity with a similar mission or constituency, as determined by the Company and the office of the Governor of the State in their sole discretion in accordance with the requirements of RCW 80.80.100(4)(b).

(d) Each Board Member shall have one vote. The affirmative vote of a number of Board Members equal to a majority of Board Members on any Grant Review Board plus one shall constitute a "Supermajority".

(e) The entity authorized to designate a Board Member pursuant to Sections 4(b) and 4(c) shall have the authority to remove such Board Member, with or without cause, by written notice to such Grant Review Board and the Board Members thereof. In the event that any Board Member ceases to serve as a Board Member for any reason, the resulting vacancy on such Grant Review Board shall be filled by a replacement Board Member designated by the entity authorized to designate such member pursuant to Sections 4(b) and 4(c) by written notice to such Grant Review Board and the Board Members thereof.

(f) Each Board shall select its own chairperson.

(g) Subject to the terms of Section 5, the Weatherization Board shall, no later than January 1, 2013, adopt by a Supermajority (i) the process by which persons may submit applications for Grants to be made from the applicable Account, including the procedure for preliminary review of applications, (ii) the criteria and standards by which Grants may be made and (iii) a non-binding schedule of anticipated Grants by category (clauses (i), (ii) and (iii), collectively, the "Grant Procedures"). Subject to the terms of Section 5, the Economic and Community Development Board and the Energy Technology Board shall, no later than January 1, 2015, adopt by a Supermajority of its Board Members Grant Procedures with respect to each of the Economic and Community Development Fund and the Energy Technology Fund, respectively. The Grant Review Boards will jointly establish and maintain a single website to make such Grant Procedures and announcements relating to solicitations of proposals and awards of bids readily available to the public and shall further publicize such solicitations in a manner which the Grant Review Boards deem appropriate in its reasonable discretion, with all reasonable costs and expenses incurred as a result of the establishment or maintenance of such website and any such publicity to be payable from the applicable Account in accordance with the terms of Section 4(l).

(h) A Grant shall be made from an Account only following the affirmative written consent of a Supermajority of the Board Members of the applicable Grant Review Board, which consent must set forth the amount of such Grant, the recipient of such Grant, the date or dates upon which such Grants are to be made and any conditions to which the payment of Grant proceeds is subject; provided, however, that all Grants shall be made only for Proper Grant Purposes. No Grants may be authorized from the Weatherization Fund prior to the later to occur of (i) the execution by the Company or an affiliate of a Qualified Power Purchase Agreement (as defined in Section 8(c) below) and (ii) July 1, 2013. No Grants may be authorized from the Economic and Community Development Fund or the Energy Technology Fund prior to December 31, 2015.

(i) Following the affirmative written consent of a Supermajority of the Board Members of a Grant Review Board, the member or members of such Grant Review Board appointed by the Company shall be authorized to deliver to the Account Agent a letter of direction, in accordance with the terms of the Account Agreement, authorizing the Account Agent to make such Grants from the Accounts as have been authorized pursuant to Section 4(h).

(j) Meetings of each Grant Review Board shall be held quarterly, except that a Supermajority of the Board Members of any Grant Review Board may call special meetings of such Grant Review Board. Board Members may participate in a meeting of a Grant Review Board by means of conference telephone or similar communications equipment by means of which all persons participating in the meeting can hear each other, with such participation constituting presence in person at such meeting. Written or oral notice of regular or special meetings of each Grant Review Board shall be given at least two days prior to the date of the meeting. A Board Member may waive notice of a meeting either before or after the meeting by written waiver or attendance at the meeting. Board Members may vote at any meeting either in person or by proxy executed in writing.

(k) Board Members shall not be entitled to any remuneration for their service on any Grant Review Board.

(l) Costs associated with administering the grant process, the Accounts or the Grant Review Boards, including without limitation reasonable costs relating to accounting, establishment of systems for payment of Grants and expenses incurred by Board Members, shall be payable from the applicable Accounts. Board Members shall be entitled to be reimbursed for costs and expenses incurred as a result of serving on a Grant Review Board or attending meetings of a Grant Review Board to the extent such reimbursement would be permitted to be made to a person serving on a class one group board established by the State of Washington under RCW 43.03.220 and pursuant to the State Administrative and Accounting Manual, as published by the Washington State Office of Financial Management.

5. Publicity and Naming Rights.

(a) All press releases and other announcements regarding the solicitation, award or distribution of individual Grants shall be made in coordination with and give recognition to the Company. The State, the Grant Review Boards and the Board Members shall not, directly or indirectly, issue any such press release or make any such announcement without the prior consent of the Company, not to be unreasonably withheld.

(b) The Company shall have the authority to designate names for each Grant or series of Grants in recognition of its financial support. If the Company or TransAlta changes its name or corporate image at any time during the term of this MOA, the Company may designate related changes to the names of the Grants.

6. SNCR Installation. No later than January 1, 2013, the Company shall install SNCR equipment in each Boiler on the terms and conditions set forth in the Department of Ecology administrative order, First Revision: Order No. 6426, dated December 13, 2011, regarding the Best Available Retrofit Technology for the eligible emission units at the Facility

(the "BART Order"). The Company and the State have discussed the proper use of ammonia in this technology as required by RCW 80.80.100(2)(b), and the Company shall operate the Facility in conformance with the requirements set forth in Section 2 of the BART Order.

7. Recognition of Investments in Emissions Reductions. In the event that the Company elects to reduce greenhouse gas emissions in excess of the emission reductions required by RCW 80.80.040(3)(c) ("Additional Emissions Reductions"), the State shall recognize such Additional Emissions Reductions in applicable state policies and programs relating to greenhouse gas emissions, and shall use its reasonable best efforts to cause the Additional Emissions Reductions to be recognized for the benefit of the Company in applicable regional, national or international policies and programs relating to greenhouse gas emissions. Further, the State agrees to recognize the Company's shut-down of the Facility's boilers prior to the end of their useful lives by taking the early shut-down into consideration during future environmental regulatory processes that may adversely affect the Facility's operations. This shall entail providing TransAlta with an opportunity to consult with Department of Ecology officials prior to final promulgation of environmental rules or other regulatory requirements. Such consultation shall occur upon written request of the Company to the Department of Ecology and, at the Company's request, shall include participation of a representative of the Governor's Office.

8. Termination.

(a) This MOA may be terminated by the Company effective immediately upon written notice to the State at any time prior to or following the Effective Date upon the issuance by any governmental agency of a determination (i) that selective catalytic reduction technology must, as a matter of state or federal law, be installed on either or both of the Boilers or (ii) that conditions any rights or privileges on the installation of selective catalytic reduction technology on either or both of the Boilers.

(b) This MOA may be terminated by the Company effective immediately upon written notice to the State if any or all tax exemptions applicable to the Company and the Facility under RCW 82.08.811 or RCW 82.12.811, in either case as in effect on July 22, 2011 (the "Specified Sales and Use Tax Exemptions"), are repealed or amended in a manner that reduces or impairs the ability of the Company or its affiliates to utilize such tax exemptions.

(c) This MOA may be terminated by the Company effective upon five (5) business days' written notice to the State if, as of December 15, 2012, the Company or an affiliate has failed, despite the exercise of its commercially reasonable efforts, to negotiate and execute one or more power purchase agreements including terms and conditions relating to force majeure, outages and resupply rights, for the sale of at least 500 megawatts of the baseload electrical output of the Facility with one or more consumer-owned utilities or electrical companies as defined in RCW 80.80.010, with the Bonneville Power Administration, or with consumers located in Washington State, for a term of at least eight years ("Qualified Power Purchase Agreements"); provided, however, that during the five (5) business day period following notice of termination pursuant to this Section 8(c), the Parties may agree to extend the term of this MOA for an additional year, in which case this MOA may be terminated by the Company effective upon written notice to the State if, as of December 15, 2013, the Company or

an affiliate has failed, despite the exercise of its commercially reasonable efforts, to negotiate and execute a Qualified Power Purchase Agreement. Subject to entry into a mutually acceptable confidentiality agreement, in connection with exercise of the termination right set forth in this Section 8(c), the Company shall provide the Governor of the State of Washington or a designee thereof the opportunity to review all provisions of such power purchase agreements that relate to quantity or duration of power sold and the location of the facility taking delivery of such power.

(d) This MOA may be terminated by the Company effective immediately upon written notice to the State if the Company (i) has reasonably determined that the cost of replacements, improvements, capital investments or additions required to continue to operate the Facility, combined with the Facility's operating costs, over the remaining life of the Facility will exceed the reasonably foreseeable financial return to the Company from continued operation of the Facility over such period and (ii) on the basis of such determination has permanently ceased power generation operations of the Facility.

9. Effect of Termination.

(a) In the event this MOA is terminated pursuant to Section 8(a) or 8(c), all amounts in the Accounts that have not been disbursed prior to the effectiveness of such termination, including for the avoidance of doubt all interest and gains earned on funds in the Accounts, shall be immediately returned to the Company. In the event this MOA is terminated pursuant to Section 8(b) and the repeal or amendment of the Specified Sales and Use Tax Exemptions is applied retroactively, an amount of cash in the Accounts equal to the marginal tax liability resulting from such retroactive application shall be immediately returned to the Company.

(b) In the event this MOA is terminated pursuant to Sections 8(a), 8(b), or 8(c), this MOA shall become void and of no further force or effect, with no liability or obligation hereunder on the part of either Party or any of their respective affiliates, officers, managers, directors, employees, members or shareholders, except that Sections 6, 8(a), 10, 11 and 12 shall survive such termination.

(c) In the event this MOA is terminated pursuant to Section 8(d), the Company shall have no obligation to make any annual payments after notice of termination and this MOA shall terminate upon the date that all funds in any Accounts have been applied to Grants or otherwise applied as provided herein. Upon such termination, this MOA shall become void and of no further force or effect, with no liability or obligation hereunder on the part of either Party or any of their respective affiliates, officers, managers, directors, employees, members or shareholders, except that Sections 8(a), 10, 11 and 12 shall survive such termination.

(d) Termination of this MOA pursuant to Section 8 shall not in any manner impact the validity or enforceability of contracts or agreements entered into by the Parties, other than this MOA, prior to the date of such termination, including Qualified Power Purchase Agreements or other agreements for the sale of electrical output of the Facility.

10. Records Review. The Company agrees that the State or its designated representatives shall have the right to review and, as to any non-confidential documents, to copy

any records and supporting documentation pertaining to the obligations of the Company under this MOA, including review of any records with respect to the Accounts. Prior to the termination of this MOA, the Company agrees to maintain all such records for a minimum of seven years, and following the termination of this MOA, the Company agrees to maintain all such records for a minimum of three years. The Company agrees to allow access to such records during normal business hours.

11. Enforcement.

(a) If there is a dispute between the Parties relating to or arising out of this MOA, the Parties agree to escalate the dispute for resolution by senior management of the Company and a senior advisor within the office of the Governor of the State of Washington, on behalf of the State.

(b) If the senior management of the Company and a senior advisor within the office of the Governor are unable to resolve the dispute, either Party may, by written notice to the other, submit such dispute to non-binding mediation pursuant to RCW 7.07. Mediation in accordance with this Section 11(b) will be conducted by a mediator mutually selected by the Parties; provided that if the Parties fail to mutually select a mediator within ten business days after such notice, then the Parties will follow the mediator selection procedures in accordance with the American Arbitration Association Commercial Arbitration Rules and Mediation Procedures. Each Party will bear its own costs in such mediation, and the mediator's fee will be divided evenly between the Parties.

(c) If the Parties are unable to resolve the dispute through mediation, either Party shall have the full right to seek resolution of the dispute through legal action. Any claims relating to a dispute arising out of this MOA that are not resolved in non-binding mediation as provided in Section 11(b) must be brought in the superior court for Lewis County, Washington or, to the extent a federal court has jurisdiction over such dispute, federal court located in Tacoma, Washington.

(d) Subject to Section 11(f), each Party shall be entitled to all rights and remedies provided by law or in equity. Each Party recognizes and agrees that monetary damages may not be a sufficient remedy for breaches of this MOA, and that each Party shall be entitled, without waiving any other rights or remedies, to such injunctive and/or other equitable relief to prevent a breach of the provisions of this MOA, or any part thereof, as may be deemed proper by a court of competent jurisdiction.

(e) In the event that a court of competent jurisdiction finds that the State has materially breached any of its covenants or agreements contained herein, the Company shall be entitled to rescission or termination of this MOA, and shall be entitled to immediate return of all amounts in the Accounts that have not been disbursed prior to the entry of the applicable court order, including for the avoidance of doubt all interest and gains earned on funds in the Accounts.

(f) Each Party acknowledges and agrees that any controversy which may arise under this MOA is likely to involve complicated and difficult issues, and therefore each

Party hereby irrevocably and unconditionally waives any right such Party may have to a trial by jury in respect of any litigation directly or indirectly arising out of or relating to this MOA, or the transactions contemplated by this MOA.

12. Miscellaneous.

(a) *No Third Party Beneficiaries*. The provisions of this MOA are intended solely for the benefit of the Parties, and this MOA shall not confer any rights or remedies upon a person other than the Parties.

(b) *Successors and Assigns*. The provisions of this MOA will inure to the benefit of, and be binding on, the Parties and their successors and assigns.

(c) *Force Majeure*. No Party shall be liable or responsible to the other Party, nor be deemed to have defaulted under or breached this MOA, for any failure or delay in fulfilling or performing any term of this MOA, when and to the extent such failure or delay is caused by or results from acts beyond the affected Party's reasonable control, including, without limitation: (i) acts of God; (ii) flood, fire, earthquake or explosion; (iii) war, invasion, hostilities (whether war is declared or not), terrorist threats or acts, riot or other civil unrest; (iv) government order or law, (v) actions, embargoes or blockades in effect on or after the date of this MOA; (vi) action by any government or agency, bureau, board, commission, court, department, official, political subdivision, tribunal or other instrumentality of any government, whether federal, state or local (each, a "Governmental Body"), or the failure by any Governmental Body to comply with statutorily mandated permitting time requirements; (vii) national or regional emergency; (viii) strikes, labor stoppages or slowdowns or other industrial disturbances; and (ix) interruption or curtailment of the transportation, distribution, storage or other delivery of coal for non-economic reasons (each, a "Force Majeure Event"); provided, that the State's obligations under this MOA may not be excused pursuant to the terms of subsections (iv) or (vi) of this Section 12(c) if the Force Majeure Event is caused by the action or inaction of the State of Washington. The Party suffering a Force Majeure Event shall give notice within seven days of the Force Majeure Event to the other Party, stating the period of time the occurrence is expected to continue and shall use commercially reasonable efforts to end the failure or delay and ensure the effects of such Force Majeure Event are minimized.

(d) *Governing Law*. This MOA shall be construed and administered in accordance with and governed by the laws of the State of Washington, and the Laws of the United States of America applicable therein.

(e) *Consent to Jurisdiction*. Subject to the provisions of Section 11, in connection with any disputes arising under this MOA, the Parties hereby submit to the jurisdiction of state court located in Lewis County, Washington.

(f) *Severability*. The Parties intend and believe that each provision of this MOA comports with all applicable local, state and federal laws and judicial decisions. However, if any term or other provision of this MOA other than Section 8(c) or 9(a) is found by a court of law to be in violation of any applicable local, state or federal ordinance, statute, law, administrative or judicial decision, or public policy, and if such court should declare such term

or provisions of this MOA to be illegal, invalid, unlawful, void or unenforceable as written, then it is the intent of the Parties that such term or provisions shall be given force to the fullest possible extent that they are legal, valid and enforceable, that the other conditions and provisions of this MOA shall be construed as if such illegal, invalid, unlawful, void or unenforceable term or provision were not contained herein, and that the rights, obligations and interest of the Parties under the remainder of this MOA shall remain in full force and effect, provided that enforcement of such remainder of the MOA does not materially modify either Party's burdens and benefits under the MOA. Upon such determination that any term or other provision is illegal, invalid, unlawful, void or unenforceable as written, the Parties shall negotiate in good faith to modify this MOA so as to effect the original intent of the Parties as closely as possible in a mutually acceptable manner. If the Parties cannot agree to such a modification and a Party believes that it will suffer a material adverse effect due to the severance of one or more unenforceable terms or provisions, that Party may rescind or terminate this MOA upon notice to the other Party.

(g) *Entire Agreement.* This MOA constitutes the entire agreement between the Parties with respect to the subject matter hereof and no representations, promises or agreements, oral or otherwise, between the Parties not embodied herein shall be of any force or effect.

(h) *Reopener; Modification.* The Parties agree that, if either Party provides notice to the other Party requesting to meet to discuss modification of this MOA, the Parties shall meet and negotiate in good faith to modify the MOA to the mutual satisfaction of the Parties. Notwithstanding the foregoing, no provisions of this MOA may be changed, waived, discharged or terminated orally, but only by written instrument executed by both Parties.

(i) *Counterparts and Facsimile Signatures.* This MOA may be executed by the Parties through execution of identical counterpart agreements, each of which when executed shall constitute a single agreement. Facsimile signatures shall be deemed equivalent to original signatures.

(j) *Notice.* Any notice required from a Party under this MOA shall be written and shall be sent by personal delivery, messenger service, facsimile or nationally recognized courier service, with a separate copy of such notice to be delivered by e-mail, in each case to the address, facsimile number or e-mail address of such Party as set forth below. A Party may change its address for purposes of notice upon notice to the other Party. Any notice provided by a Party under this MOA shall be deemed received (i) on the date of delivery if delivered personally and/or by messenger service, (ii) on the date of confirmation of receipt of transmission by facsimile or (iii) one business day after being sent by nationally recognized courier service.

If to the State:	*If to Company:*
Governor's Executive Policy Office PO Box 43113 Olympia, WA 98501-3113 Attention: Keith Phillips Telephone No.: (360) 902-0630 Facsimile No.: (360) 586-8380 Email: Keith.Phillips@gov.wa.gov and Attorney General's Office, Ecology Division PO Box 40117 Olympia, WA 98502 Attention: Laura J. Watson Facsimile No.: (360) 586-6760 Email: LauraW2@atg.wa.gov	TransAlta Centralia Generation LLC c/o TransAlta USA, Inc. 724 Columbia Street NW, Suite 320 Olympia WA 98501 Attention: Lori Schmitt Telephone No.: (360) 742-3052 Facsimile No.: (360) 742-3093 Email: Lori_Schmitt@transalta.com with a copy (which shall not constitute notice to the Company) to: K&L Gates LLP 425 Fourth Avenue, Suite 2900 Seattle, WA 98104 Attention: Liz Thomas Facsimile No.: (206) 370-6190 Email: liz.thomas@klgates.com

[Signature page follows]

IN WITNESS WHEREOF, the Parties have executed this Memorandum of Agreement as of the day and year first set forth above.

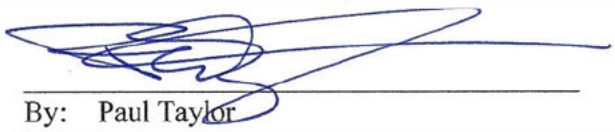
THE STATE OF WASHINGTON



By: Christine O. Gregoire
Title: Governor

THE COMPANY

TRANSALTA CENTRALIA GENERATION LLC



By: Paul Taylor
Its: President

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-107:
Shutdown Memorandum of Understanding

Memorandum of Understanding

Having reached an agreement in principle in March 2011, and worked together to successfully pass legislation in Washington State[1] to transition the coal-fired power plant owned by TransAlta in Centralia, Washington away from combustion of coal, TransAlta, Climate Solutions, the NW Energy Coalition, the Sierra Club and the Washington Environmental Council agree to:

1. Mutually support and advocate to the US EPA regarding the agreement they have reached to transition the facility, pursuant to the terms of the 2011 legislation.

2. Accept and not oppose the sale of coal transition power from the facility to potential buyers and be willing to speak to the positive environmental outcomes resulting from any sale, the agreement, and the legislation.

3. Mutually support or not oppose, consistent with each group's customary roles and activities, the approval of power sales of coal transition power by the Washington Utilities and Transportation Commission, or any other appropriate regulatory body if the power sales contract is in the public interest.

4. Ensure that sales from the plant for the remaining duration of its operations support appropriate investments in community transition and economic development, energy efficiency and clean energy as articulated in the legislation and MOA.

The parties acknowledge that the Memorandum of Agreement between Washington state and TransAlta stipulates that the agreement can be terminated if long-term power purchase agreements are not achieved by December 2012 (or December 2013 if extended).[2] The parties desire to see sufficient long term power sales to fully preserve the benefits to the company, community and the environment that are contained in the MOA.

This memorandum of understanding between the undersigned parties expires December 31, 2025 or on the day the Memorandum of Agreement referenced above is terminated or expires.

Paul Taylor Date: June 26, 2012
President, TransAlta Centralia Generation, LLC

See signature page attached

Bruce Nilles Date: 6/22/2012
Senior Director, Sierra Club

Joan Crooks Date: 6/22/2012
Executive Director, Washington Environmental Council

Gregg Small Date: 6/21/2012
Executive Director, Climate Solutions

Sara Patton Date: 6/22/2012
Executive Director, NW Energy Coalition

[1] http://apps.leg.wa.gov/billinfo/summary.aspx?bill=5769&year=2011
[2] MOA, agreements #3 and #8(c)

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Paul Taylor Date: _____
President, TransAlta Centralia Generation, LLC

Bruce Nilles Date: June 22, 2012
Senior Director, Sierra Club

Joan Crooks Date: _____
Executive Director, Washington Environmental Council

Gregg Small Date: _____
Executive Director, Climate Solutions

Sara Patton Date: _____
Executive Director, NW Energy Coalition

[1] http://apps.leg.wa.gov/billinfo/summary.aspx?bill=5769&year=2011
[2] MOA, agreements #3 and #8(c)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-108:
Order Approving Puget-TransAlta Power Purchase Agreement

[Service Date January 9, 2013]

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of	)	DOCKET UE-121373
	)	
PUGET SOUND ENERGY, INC.,	)	ORDER 03
	)	
For Approval of a Power Purchase Agreement for Acquisition of Coal Transition Power, as Defined in RCW 80.80.010, and the Recovery of Related Acquisition Costs	)	FINAL ORDER GRANTING PETITION, SUBJECT TO CONDITIONS
. . . . .	)	

Synopsis: *The Commission approves a power purchase agreement between Puget Sound Energy, Inc. (PSE), and TransAlta Centralia Generation LLC that provides for PSE's acquisition of an average 346 MW of coal transition power, as defined in RCW 80.80.010, over a contract term of 133 months. The Commission determines that PSE is authorized by statute to recover, in addition to its costs of power, equity return in the amount of $1.49 per MWh for all deliveries of power under the contract. This "equity adder," a unique contract incentive provided by statute exclusively for the purchase of coal transition power, will result in PSE receiving $44.12 million in nominal return on equity, having a net present value of $34.15 million over the full term of the contract, without requiring any capital investment by the company.*

The Commission's approval of the agreement is subject to a condition that PSE will file an annual report allowing the Commission to fulfill its obligation on an ongoing basis to regulate in the public interest, as provided by the public service laws, including specifically to effect the purposes of the statute establishing the legal concept of "coal transition power," which has the purpose, among others, of preserving family wage jobs. The report will enable the Commission to evaluate whether the subject power purchase agreement may be found to have lost its character as an agreement for the sale and delivery of coal transition power due to changed circumstances in plant operations, or a failure to satisfy the provisions of RCW Chapter 80.80 on an ongoing basis.

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SUMMARY

1 **PROCEEDING:** On August 20, 2012, Puget Sound Energy, Inc. (PSE or Company) filed with the Washington Utilities and Transportation Commission (Commission) a Petition for Approval of a Power Purchase Agreement for Acquisition of Coal Transition Power, as Defined in RCW 80.80.010, and the Recovery of Related Acquisition Costs (Petition). The subject Coal Transition Purchase Power Agreement (Coal Transition PPA) is between PSE and TransAlta Centralia Generation LLC (TransAlta Centralia).

2 PSE requests an order: (1) approving the Coal Transition PPA, subject to and conditioned upon certain Commission determinations and findings specified in Section VI of the Petition; (2) approving PSE's recovery of the equity component of the Coal Transition PPA as provided in RCW 80.04.570(6); (3) approving deferral of certain costs associated with the Coal Transition PPA throughout the entire term of the Coal Transition PPA including later volume and pricing changes; and (4) finding that the Coal Transition PPA is prudent, regardless of whether the term of the Coal Transition PPA terminates upon its expiration or is terminated prior to its expiration.

3 **PARTY REPRESENTATIVES:** Sheree Strom Carson, Jason Kuzma and Donna Barnett, Perkins Coie, Bellevue, Washington, represent PSE. Simon ffitch and Lisa W. Gafken, Assistant Attorneys General, Seattle, Washington, represent the Public Counsel Section of the Washington Office of Attorney General (Public Counsel). Sally Brown and Greg Trautman, Assistant Attorney's General, Olympia, Washington, represent the Commission's regulatory staff (Commission Staff or Staff).[1]

4 Melinda Davison and Joshua Weber, Davison Van Cleve, Portland, Oregon, represent the Industrial Customers of Northwest Utilities (ICNU). Danielle Dixon, Senior

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

Policy Associate, and Nancy Hirsch, Policy Director, Northwest Energy Coalition (NWEC), represent NWEC.

5 **COMMISSION DETERMINATIONS:** The Commission determines that it should approve PSE's Petition, subject to a condition requiring an annual report deemed necessary to protect ratepayers and the broader public interest, as required in the legal and policy environment that establish the concept of "coal transition power." Based on our evaluation of the Coal Transition PPA in the context of Chapter 80.80 RCW, RCW 80.04.570 and the Memorandum of Agreement between TransAlta and the Governor's office that is required under RCW 80.80.100, we find the Coal Transition PPA acceptable and within the bounds the prudence standards that we apply to such an agreement. The Coal Transition PPA, however, includes certain provisions that could give rise to further Commission inquiry if TransAlta substantially limits operation of the Centralia plant.

6 We are concerned specifically with the potential that the power TransAlta commits to deliver could lose its character as "coal transition power," as we understand the term within its statutory definition and other provisions of law that establish its essential characteristics. We are most concerned with two circumstances that are unlikely, according to our record, but nevertheless conceivable, circumstances. One is that, contrary to PSE's expectations,[2] TransAlta will not continue to operate the Centralia Coal Facility and therefore satisfy most, albeit not necessarily all, of its delivery obligations with power from the plant. This could mean, among other things, the loss of family-wage jobs, the preservation of which is one policy goal of the Coal Transition Energy Bill. The other concern is that TransAlta will not continue to provide the financial assistance provided for under RCW 80.80.100 and contractually memorialized in the Memorandum of Agreement (MOA) between TransAlta and the Governor's Office. The legislature expressly contemplates in RCW 80.80.100 that in exchange for the benefits conferred by the Coal Transition Energy Bill will help fund the transition of the local economy in the region that depends on the Centralia Coal Facility as an economic mainstay. Yet, there are various opportunities for TransAlta to terminate the MOA, both as specified in RCW 80.80.100, and otherwise. This means these funds conceivably could be lost.

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[2] *See, e.g., TR. 235:15-239:3; 240:3-8; 241:8-244:16; 259:16-260:11 (Kuzma).*

7 In light of these concerns, we condition our approval of the Coal Transition PPA by requiring an annual report from PSE that will enable the Commission to engage in some ongoing scrutiny of the implementation of the statute and PPA. Given the unique nature of the Coal Transition PPA, we recognize that the Commission may determine at some point in the future that its expectations under the legal and policy environment in which the concept of coal transition power resides are not being met. The Commission may then evaluate whether to revisit some aspects of the Coal Transition PPA.

8 In addition to determining that the Coal Transition PPA should be approved as presented, subject to the imposition of a reporting requirement, we also resolve several issues related to PSE's cost-recovery proposals. We find that the equity adder to which PSE is entitled under RCW 80.04.570(6) should be based on a hypothetical "equivalent plant" cost of $110 million. We accept PSE's proposals to calculate the return amount using its currently authorized 7.24 percent pre-tax weighted average cost of equity over the term of the contract and to levelize the recovery of return using PSE's methodology, which recognizes the time-value of the stream of equity return payments to which the Company is entitled during the life of the contract.

9 As to PSE's request that it be authorized to defer incremental costs that arise between rate proceedings with changes in volume, price or both during the term of the Coal Transition PPA, we think it better to postpone consideration of the issue until PSE seeks recovery of the initial costs of the PPA that it will begin to incur on December 1, 2014. PSE acknowledges that this date, nearly two years from now, leaves ample opportunity for the Company to file either a general rate case or a Power Cost Only Rate Case (PCORC). Either of these proceedings would be a more appropriate one for consideration of cost accounting questions.

MEMORANDUM

I. Background and Procedural History

10 TransAlta Centralia owns and operates a baseload coal-fired electric generating plant of approximately 1340 megawatts of electric generating capacity located at Centralia,

Washington. The plant consists of two generation units and two boilers. The plant is subject to Chapter 80.80 RCW, which imposes an emissions performance standard on baseload electric generation in the State of Washington. Under the statute, as originally enacted, electric utilities such as PSE could not enter into a long-term financial commitment for baseload electric generation from the Centralia plant on or after July 1, 2008, because the generating plant's emissions exceed the emissions performance standard of 1100 pounds of greenhouse gases per megawatt-hour.[3]

11 On May 21, 2009, Governor Gregoire issued Executive Order 09-05, Washington's Leadership on Climate Change, which directed the Department of Ecology to work with TransAlta Centralia to establish an agreed order to apply the emissions performance standard to the Centralia Coal Facility by no later than December 31, 2025. On April 26, 2010, Governor Gregoire and TransAlta Centralia entered into a memorandum of understanding to enter discussions on an agreement to reduce gas emissions from the Centralia Coal Facility and provide replacement capacity by 2025.

12 On April 29, 2011, Governor Gregoire signed Engrossed Second Substitute Senate Bill 5769 (Coal Transition Energy Bill), which provides certain deferrals of the greenhouse gas emissions performance standard to encourage the early closure of coal plants in Washington. As a practical matter, this meant the Centralia facility, the only such plant operating in Washington. The Coal Transition Energy Bill amended RCW 80.80.040 to allow the Centralia facility to comply with greenhouse gas emissions performance standards by shutting down one of its two boilers by the end of 2020 and the other by the end of 2025.[4]

13 The Coal Transition Energy Bill amended RCW 80.80.040 to allow electric utilities such as PSE to enter into new financial commitments for the output from the facility for terms greater than five years. The Coal Transition Energy Bill also established a process that allows such electric utilities to petition the Commission for approval of a power purchase agreement for coal transition power.[5] If such a contract is approved, the utility is allowed to earn and recover the equity

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[3] *See* RCW 80.80.040(1)(a) and RCW 80.80.040(1)(c)(i)(A).

[4] RCW 80.80.040(1)(c)(i)(A).

[5] *See* RCW 80.04.570(6) and WAC 480-100-415.

component of its authorized rate of return in the same manner as if it had purchased or built an equivalent plant and to recover the cost of the coal transition power under the power purchase agreement. This truly unique equity adder is expressly limited to "an agreement for acquisition of coal transition power" and does not apply to "any other power purchase agreement or other power contract."[6]

14 On December 23, 2011, Governor Gregoire and TransAlta Centralia entered into the MOA, which memorialized in contractual form the arrangements set forth in the Coal Transition Energy Bill.[7] The MOA between TransAlta Centralia and the State of Washington is effective as of April 1, 2012 and expires no earlier than December 31, 2025, unless terminated earlier pursuant to its terms.[8]

15 On July 24, 2012, PSE and TransAlta Centralia entered into the Coal Transition PPA that is the subject of this proceeding. It provides that PSE will purchase up to 380 MW of coal transition power from what the PPA refers to as the Centralia Transition Coal Facility (CTCF), with average deliveries over the life of the contract of 346 MW. The contract quantity varies over time and the price increases over time.[9] Starting on December 1, 2014, the initial quantity is 180 MWh/hr. The quantity increases to 280 MWh/hr on December 1, 2015, and to 380 MWh/hr on December 1, 2016. The delivery rate thereafter remains steady through December 31, 2024. On January 1, 2025, the contract quantity decreases to 300 MWh/hr through the termination date, December 31, 2025.

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[6] RCW 80.04.570(8). The Commission is keenly aware that the Legislature strictly limited the applicability of an equity adder concept to coal transition contracts and did not authorize such a feature in connection with any other power purchase agreement or, indeed, any other form of contract for the sale and purchase of electricity. The action we take here, therefore, cannot be considered precedential in any sense or an indication of a change in the Commission's traditional views regarding the regulatory treatment of purchased power.

[7] *See* Exhibit No. RG-8HC at 434-447. *See also* RCW 80.80.100.

[8] *Id.*

[9] *See* Exhibit No. RG-1HCT at 9:1-11:2; *see also* Exhibit No. RG-3C at 16-17 (Coal Transition PPA Section 3.1) and 45 (Exhibit B to Coal Transition PPA). The exact pricing terms are designated "Confidential" under Order 01 Protective Order with "Highly Confidential" Provisions, entered in this proceeding on September 10, 2012.

16 On August 20, 2012, PSE filed its Petition seeking Commission approval of the Coal Transition PPA under RCW 80.04.570.[10] PSE's filing included supportive testimony and exhibits by Ms. Barnard, Mr. Bevil, Mr. Garratt and Ms. Selig.[11]

17 Staff, Public Counsel and NWEC each filed response testimony and exhibits on November 2, 2012. Each party sponsors one witness: Mr. Gomez for Staff, Mr. Woodruff for Public Counsel and Ms. Dixon for NWEC. While it is fair to observe that none of these witnesses flatly opposed Commission approval of the Coal Transition PPA, it is equally fair to observe that none offers unqualified support for PSE's Petition. Although ICNU did not file testimony, its representative participated in oral argument following the evidentiary hearing and supported various positions taken by these parties.

18 Mr. Garratt and Ms. Barnard filed rebuttal testimony for PSE on November 16, 2012. They contest the principal issues raised by the response testimonies and clarify PSE's initial filing with respect to certain secondary issues. Mr. Garrett filed supplemental rebuttal testimony on November 19, 2012 in response to corrections Mr. Gomez filed to his responsive testimony on November 15, 2016.

19 The Commission conducted evidentiary hearings on December 12, 2012. We heard oral argument from all parties on December 20, 2012.

II. Issues

20 The Legislature has set forth the standards, which, if met, mean that we "must approve" the PPA.

> The commission must approve a power purchase agreement for acquisition of coal transition power pursuant to this section only if the

[10] Petition for Approval of a Power Purchase Agreement for Acquisition of Coal Transition Power, as Defined in RCW 80.80.010, and the Recovery of Related Acquisition Costs.

[11] Ms. Barnard testifies concerning the proposed cost recovery methodology. Mr. Bevil testifies about 2011 RFP process and the quantitative and qualitative evaluation of the TransAlta CTPPA. Mr. Garratt testifies about the IRP and RFP and the Company's internal decision-making processes and about PSE's proposed calculation of the equity component allowed under the statute. Ms. Selig offers a more detailed look into PSE's quantitative analyses.

> commission determines that, considering the circumstances existing at the time of such a review: The terms of such an agreement provide adequate protection to ratepayers and the electrical company during the term of such an agreement or in the event of early termination; the resource is needed by the electrical company to serve its ratepayers and the resource meets the need in a cost-effective manner as determined under the lowest reasonable cost resource standards under chapter 19.280 RCW, including the cost of the power purchase agreement plus the equity component as determined in this section. As part of these determinations, the commission shall consider, among other factors, the long-term economic risks and benefits to the electrical company and its ratepayers of such a long-term purchase.[12]

Further, the Legislature set forth the methodology for determining the "equity component" the utility entering into such a PPA may earn.

> (6)(a) Upon commission approval of an electrical company's power purchase agreement for the acquisition of coal transition power in accordance with this section, the electrical company is allowed to earn the equity component of its authorized rate of return in the same manner as if it had purchased or built an equivalent plant and to recover the cost of the coal transition power under the power purchase agreement. Any power purchase agreement for the acquisition of coal transition power that earns a return on equity may not be included in an imputed debt calculation for setting customer rates.
> (b) For purposes of determining the equity value, the cost of an equivalent plant is the least cost purchased or self-built electric generation plant with equivalent capacity. In determining the least cost plant, the commission may rely on the electric company's most recent filed integrated resource plan. The cost of an equivalent plant, in dollars per kilowatt, must be determined in the original process of commission approval for each power purchase agreement for coal transition power.
> (c) The equivalent plant cost determined in the approval process must be amortized over the life of the power purchase agreement for acquisition of coal transition power to determine the recovery of the equity value.

[12] RCW 80.04.570(4).

> (d) The recovery of the equity component must be determined and approved in the review process set forth in this section. The approved equity value must be in addition to the approved cost of the power purchase agreement.[13]

21 No party contests PSE on the question whether the Coal Transition PPA is needed by the Company to serve customers. Mr. Gomez testifies that "Staff stipulates that the [Coal Transition] PPA is needed by PSE to serve its ratepayers over the term of the contract, and that the [Coal Transition] PPA meets this need in a cost-effective manner."[14] Staff and the other parties do not oppose Commission approval of the Coal Transition PPA but recommend that various conditions be imposed to provide "adequate protection to ratepayers," as required under RCW 80.04.570(4).

22 Staff and Public Counsel challenge PSE on the question of what is the cost of an equivalent plant for purposes of determining how much equity return PSE should be allowed to recover under the statute.[15] As summarized below, Staff raises several additional issues related to the "equity adder" proposed by PSE:

- Staff and Public Counsel challenge PSE's proposal to measure the cost of an equivalent plant based on a bid the Company received during its most recent Integrated Resource Plan (IRP) and associated Request for Proposals (RFP) process, but rejected.[16] They contend that, considering the IRP/RFP analyses and results, PSE did not select the "least cost purchased or self-built electric generation plant with equivalent capacity."[17] Staff and Public Counsel propose that the Commission rely on the Company's selection and purchase in November 2012 of the Ferndale Combined Cycle Turbine Cogeneration Facility, which was identified as a least cost option through the 2011 RFP process.

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[13] RCW 80.04.579(6).

[14] Exhibit No. DCG-1HCT at 3:16-17. Staff clarified during oral argument that this stipulation depends on the equity adder cost of the contract being based as advocated by Staff, not the higher level based on PSE's proposed "cost equivalent plant."

[15] RCW 80.04.570(6)(a).

[16] By way of shorthand reference in this Order, we sometimes refer to the two-step process as the "IRP/RFP."

[17] RCW 80.04.570(6)(b).

- Staff challenges PSE's proposal to fix the equity return throughout the term of the Coal Transition PPA at 7.24 percent, the Company's currently authorized pre-tax weighted average cost of equity return. Staff argues the return should be adjusted as set in subsequent PSE general rate cases.[18]
- There is a methodological dispute between PSE and Staff concerning the calculation of levelized costs for purposes of setting the equity adder value.
- Staff recommends that the equity adder should be allowed only for power generated by coal fuel at the CTCF or a substitute source of energy if required by an abnormal circumstance of limited duration that prevents delivery from the CTCF.

23 Public Counsel and NWEC both initially recommended that we impose conditions requiring changes in the structure and specific terms included in the Coal Transition PPA. Public Counsel withdrew its proposal during oral argument but NWEC's recommendation remains at issue. NWEC challenges Section 10.1 of the Coal Transition PPA, which implements RCW 80.04.570(2), arguing that it should be revised to establish TransAlta as the assumed risk taker in the event of future greenhouse gas emissions regulations or requirements, while still allowing for a contract reopener at the time of any such regulations or requirements to assess specific details, if needed.

24 Public Counsel initially argued that the Commission should condition approval of the Coal Transition PPA by requiring the contract to be restructured to include a unit contingency requirement (*i.e.,* PSE's obligation to take power at any given time is contingent on the plant actually operating at a certain level) and by giving PSE dispatch rights. During oral argument Public Counsel said it would not urge the Commission to require contract reformation, but instead urged that we recognize the absence of such rights in the Coal Transition PPA make it too reliant on the use of resupply power.[19] Public Counsel recommends that the Commission accept Staff's position that resupply power be narrowly defined and that PSE's right to equity return

[18] PSE states on rebuttal that while accepting Staff's recommendation will increase the complexity of the return calculation, "PSE can accept the proposal." Exhibit No. RG-10HCT at 33:15-34:2.

[19] *See* TR. 290:23-291:24 (ffitch).

should apply only to power produced by the CTCF and the limited amount of resupply power that would qualify under Staff's proposal.

25 Staff and NWEC recommend that the Commission condition approval of the Coal Transition PPA to protect the relationship between the Coal Transition PPA and TransAlta's obligations to provide financial support to affected communities under the MOA and RCW 80.80.100. Public Counsel subscribed to this position during oral argument.

26 Finally, Staff challenges PSE's proposal to defer certain costs during the life of the Coal Transition PPA.

III. Discussion and Decisions

A. Equity Return

1. What is the Cost of an "Equivalent Plant"?

27 *Commission Determination: We find that the cost of an equivalent plant for purposes of calculating the amount of equity return to which PSE is entitled under RCW 80.04.570(6) is $110 million.*

28 RCW 80.04.570(6)(a) provides that PSE is allowed to earn the equity component of its authorized rate of return on the Coal Transition PPA "in the same manner as if it had purchased or built an equivalent plant." RCW 80.04.570(6)(b) states how the Commission should determine the value of an equivalent plant for purposes of calculating the equity return to which a coal transition power purchaser is entitled under the statute:

> For purposes of determining the equity value, the cost of an equivalent plant is the *least cost* purchased or self-built electric generation plant with *equivalent capacity*. In determining the least cost plant, the commission *may rely* on the electrical company's most recent filed integrated resource plan. The cost of an equivalent plant, in dollars per kilowatt, must be determined in the original

> process of commission approval for each power purchase agreement for coal transition power.[20]

These requirements are by no means prescriptive. They offer guidance but also give the Commission significant latitude to determine the cost of an equivalent plant for purposes of calculating the equity return available for a coal transition power purchase agreement based on the record and the application of informed judgment.[21]

29 Three parties address this issue: PSE, Staff and Public Counsel. These parties all suggest that we should rely on the Company's most recently completed IRP and the associated RFP process in which the Coal Transition PPA and acquisition of Ferndale were selected as providing together the least cost means by which PSE can satisfy its capacity needs in the near to intermediate term. The parties differ, however, in their perspectives on what information garnered during this process should be the focus of our determination and they propose significantly different outcomes.

30 PSE, focusing on a plant acquisition proposal received but rejected during the 2011 RFP process, argues the cost of an equivalent plant is $215 million. Staff and Public Counsel focus on a plant acquisition bid into the 2011 RFP that PSE ultimately purchased in November 2012 for $84.2 million: the Tenaska Ferndale Cogeneration Facility (Ferndale). Staff considers Ferndale's unadjusted purchase price as the cost of an equivalent plant. Public Counsel adjusts for the larger volumes under the Coal Transition PPA relative to Ferndale's capacity and allows for certain transaction costs and costs of improvements, and arrives at $110 million as the cost of an equivalent plant.

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[20] RCW 80.04.570(6)(b) (emphasis added).

[21] This is necessary, among other reasons, because it is highly unlikely that an actual plant available for purchase at any given time will match perfectly in its operating characteristics the purchaser's requirements and seller's obligations under a purchase power agreement. Indeed, PSE's witness, Mr. Garratt, recognizes that "the Coal Transition PPA is a firm, 24x7 product, and the capacity factors of the projects bid into the 2011 RFP are less than 100%." Exhibit No. RG-1HCT at 24:16-17. Public Counsel's witness, Mr. Woodruff, testifies in this vein that "no plant can operate at a 100 percent capacity factor." Exhibit No. KDW-1HCT at 30:17-31:6. Accordingly, he says, "there is arguably no plant that is truly equivalent to the Coal Transition PPA and thus no 'true capital cost of an equivalent plant.'" *Id.*

31 Mr. Garratt explains the method PSE used to determine the equity amount it believes the Company should be entitled to recover under RCW 80.80.570(6).[22] PSE first calculated an equivalent plant size of 346 MW, based on the average volume of power to be delivered during the term of the Coal Transition PPA. PSE then calculated a projected cost of an equivalent plant of approximately $215 million, based on the per kilowatt cost of a plant ownership proposal PSE received in response to its 2011 RFP, but rejected.[23] According to Mr. Garratt, this ownership proposal for the Alternative Plant yielded the least cost purchased or self-built electric generation plant (expressed in dollars per kilowatt) among the proposals that PSE decided not to pursue as a result of the 2011 RFP.

32 Both Staff and Public Counsel contest PSE's exclusive focus on the Alternative Plant ownership proposal as the proper measure of an equivalent plant under the statute. Mr. Gomez testifies that Staff disagrees with the Company's decision to pass over what actually was the least cost purchase offer PSE received in response to its 2011 RFP, the Ferndale[24] project offered for sale by Tenaska Washington Partners. Mr. Gomez says that neither logic nor the law support PSE's view that Ferndale no longer qualifies as a touchstone for making the cost equivalent plant determination because it was chosen in the RFP for acquisition in conjunction with a revised offer PSE received from TransAlta.[25]

33 Mr. Woodruff testifies similarly that the Alternative Plant is not an appropriate measure of an equivalent plant under the statute, for several reasons. First, he

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[22] Exhibit No. RG-1HCT at 24:10-29:3; Exhibit No. RG-9.

[23] The identity of the specific plant is designated "Highly Confidential" under Order 01 Protective Order with "Highly Confidential" Provisions, entered in this proceeding on September 10, 2012. We will refer to it for purposes of this Order as the "Alternative Plant."

[24] Exhibit No. RG-8HC at 372.

[25] Exhibit No. DCG-1HCT at 9:20-12:2. Mr. Gomez also states that "the [Ferndale] plant was not chosen until after the selection of the CTCF." Mr. Garratt says on rebuttal that "PSE made the decision to acquire the Ferndale Cogeneration Station before it determined to enter into the Coal Transition PPA." Exhibit No. RG-10HCT at 26:8-9. In point of fact, it appears that Ferndale actually was chosen in conjunction with the revised Coal Transition PPA that PSE ultimately selected to meet its identified capacity needs through about 2016. *See generally* Exhibit No. CB-3HC.

agrees with Staff that this is not the least cost plant demonstrated by the 2011 RFP to be available to PSE.[26] Mr. Woodruff points out that PSE acknowledged in discovery that the lowest cost option identified in the 2011 RFP was the proposal for Ferndale, which has an estimated cost about one-half of the Alternative Plant cost.[27] He says that PSE, in its response to Staff's discovery, justified choosing the Alternative Plant proposal on the basis that it represents the "*next* lowest capital cost" resource after Ferndale. PSE's discovery response contends Alternative Plant is the "lowest capital cost resource *available* to PSE" because the Company elected to acquire Ferndale.[28]

34 Mr. Woodruff argues that the Alternative Plant is not the least cost alternative either under a plain English reading of the statute or if "least cost" is considered as a term of art in electric utility resource planning nomenclature. He says that "in the electric utility industry, the term 'least cost' refers to the "electric resource(s) expected to provide a utility's customers with reliable service at the lowest overall expected long-term cost."[29] He testifies that PSE itself found that Alternative Plant did not meet this criterion during the 2011 RFP.

35 Mr. Woodruff refers specifically to PSE's July re-evaluation of revised offers it received during the RFP evaluation process showing that the Alternative Plant is not PSE's least cost resource option.[30] The exhibit to which Mr. Woodruff refers shows that in PSE's original optimization results, the Alternative Plant was not selected as part of any least cost portfolio in any of the five analytic scenarios. Indeed, it is the only resource among ten options that was not selected in at least one of the five scenarios.[31] The Alternative Plant also was not chosen in the additional optimization analyses performed on the revised proposals PSE received on June 22, 2012, and July

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[26] Exhibit No. KDW-1HCT at 26:17-31:18.

[27] Exhibit No. KDW-14HC (PSE response to Staff Data Request No. 2).

[28] *See,* Exhibit No. KDW-14HC at 3; *See also,* Exhibit No. RG-1HCT at 25:16-20.

[29] Exhibit No. KDW-1HCT at 27:19-28:3.

[30] *Id.* at 24:4-8 (referring to Exhibit No. CB-4HC).

[31] Exhibit No. CB-4HC at 4 (Figure 2). *See also* Exhibit CB-1HCT at 25:1-3 ("the Alternative Plant ownership . . . price sensitivity analysis [showed that] the Alternative Plant ownership purchase price needed to be reduced by approximately 50% just to be least cost in three of five scenarios."

5, 2012.[32] In addition, PSE found in its qualitative review that the Alternative Plant "[p]roject economics [are] less favorable than alternatives."[33]

36 Both Mr. Gomez and Mr. Woodruff testify that the Alternative Plant also is an inappropriate selection as an equivalent plant because it does not meet the capacity criterion for selection as a resource from which to calculate the equity return component of the Coal Transition PPA.[34] Mr. Gomez testifies that as part of PSE's Phase II Qualitative Risks analysis the Company determined that the "capacity output of [the Alternative Plant] facility is large and would produce a substantial surplus of PSE's capacity need until 2016 based on current load forecast."[35] Mr. Gomez says the Ferndale facility's 280 MW is a closer match for the 327 MW[36] of average energy he calculates will be delivered to PSE from the Coal Transition PPA, and the 221 MW of capacity that was originally envisioned in the 2011 IRP for a self-build single cycle combustion turbine plant.

37 Mr. Woodruff testifies similarly that the capacity of Alternative Plant is considerably greater than the capacity of the Coal Transition PPA, which averages 346 MW and varies between 180 MW and 380 MW.[37] Mr. Woodruff says that while neither Alternative Plant nor Ferndale is precisely the same capacity as the Coal Transition PPA, Ferndale is much closer to the Coal Transition PPA's capacity and hence a better equivalent. Mr. Woodruff also points out that Alternative Plant is not among the four resources found during PSE's reevaluation of proposals to meet the

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[32] *Id*. at 5-6 (Figures 3 and 4).

[33] *Id*. at 10.

[34] The Alternative Plant, in fact, is significantly larger than the capacity acquired via the Coal Transition PPA. *See* Exhibit No. DCG-1HCT at 10:16-17; *see also* Exhibit No. KDW-1HCT at 29:9-30:2.

[35] Exhibit No. DCG-1HCT at 10:17-20 (quoting Exhibit No. CB-4HC at 10).

[36] It is not clear how Mr. Gomez calculated this number. Mr. Garratt testifies that the average volume of power to be delivered over the life of the contract is 346 MW. Exhibit No. RG-1HCT at 24:12-13. Mr. Woodruff also finds an average delivery of 346 MW. Exhibit No. KDW-1HCT at 29:9-18.

[37] Exhibit No. KDW-1HCT at 29:7-18.

Company's identified capacity need while both the Coal Transition PPA and Ferndale were determined to meet this need.[38]

38 Mr. Gomez and Mr. Woodruff offer several additional reasons why Ferndale should be considered an equivalent plant rather than the Alternative Plant. Mr. Gomez, for example, points to the RFP scoring results for Phase II showing the Alternative Plant offer as having a *negative* portfolio benefit of $62.4 million, with significantly higher risks associated with the acquisition than the Ferndale plant offer with its portfolio benefit of $96.1 million.[39] Mr. Woodruff testifies additionally that the Company's analyses show it found that there were qualitative risks associated with the condition of the plant, the availability and cost of transmission, the adequacy of the pipeline capacity, and the likely possibility that the plant could not be economically be upgraded to meet Emissions Performance Standards.[40] Thus, Mr. Woodruff concludes, there are a number of quantitative and qualitative reasons that disqualify Alternative Plant from consideration for setting the cost of an equivalent plant under RCW 80.04.570.

39 We find that the facts and analyses available to us from the 2010 IRP/2011 RFP process militate strongly in favor of using Ferndale as a key factor in our determination of a cost equivalent plant for purposes of RCW 80.04.570(6). While PSE originally identified a 500 MW power purchase agreement with TransAlta as a preferred means to meet its near-term resource needs, subsequent developments brought the 280 MW Ferndale plant to the forefront as a way to meet the Company's identified need through 2013 (*i.e.,* 242 MW).[41] The Ferndale acquisition option was selected in conjunction with negotiation of a 380 MW option for coal transition power that would add 180 MW of additional capacity in 2014 and 280 MW in 2015. These incremental increases satisfy PSE's projected needs for capacity additions (*i.e.,* 460 MW in 2014 and 554 MW in 2015). Beginning in 2016, the Coal Transition PPA would add 380 MW of capacity and,

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[38] Exhibit No. CB-4HC (Figure 11).

[39] *See* Exhibit No. DCG-1HCT at 11:3-11 (citing Exhibit No.CB-4HC at 18).

[40] Exhibit No. KDW-1HCT at 30:9-16 (citing Exhibit No. CB-4HC at 10).

[41] *See* Exhibit No. CB-1HCT at 15:6 and related discussion at 14:1-15:14. *See also* Exhibit No. RG-10HCT at 2:1-14.

again in conjunction with Ferndale, would meet much of PSE's identified supply-side capacity requirement (*i.e.,* 728 MW) at that time.[42]

40 In other words, PSE determined on the basis of its own careful analysis during the RFP process that the combination of Ferndale and the Coal Transition PPA represents the 'least cost' alternative to meet the Company's capacity needs as identified in the 2010 IRP load forecast as updated in connection with the 2011RFP process.[43] That is, these are the electric resources expected to provide PSE's customers with reliable service at the lowest overall expected long-term cost.

41 On the other hand, PSE's analyses during the 2011 RFP process showed that the Alternative Plant was not a viable option for meeting these supply side capacity needs. It cannot be regarded as a "least cost" alternative in the context of the IRP/RFP process in which PSE evaluated it. It is not by most, if any, measures equivalent to the Coal Transition PPA. Indeed, by both quantitative evaluations and qualitative considerations it cannot be found to represent the least cost mix of electric resource(s) expected to provide PSE's customers with reliable service at the lowest overall expected long-term cost. The Alternative Plant purchase offer is simply not a good measure, or basis for measurement, of the cost of a plant equivalent to the Coal Transition PPA.[44]

42 Our focus, given the evidence before us, is on what was available for purchase in response to the 2010-2011 IRP/RFP process. Ferndale was available and, indeed,

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[42] *Id.; See also* Exhibit No. RG-10HCT at 3:1 ("The Coal Transition PPA ramps to match PSE's capacity need over time") and 17:3-5 ("PSE concluded that the Ferndale Cogeneration Station ownership offer and the Coal Transition PPA offer are least cost and least risk resources after considering the quantitative and qualitative analyses performed in the 2011 RFP.").

[43] See *Id.* at 17:3-5.

[44] The fact that the Alternative Plant was arguably available as a substitute for the Coal Transition PPA, even if that argument had merit, is simply beside the point. It is entirely conceivable that no actual plant sale, or offer to sell, could be considered to be "the least cost purchased or self-built electric generation plant with equivalent capacity" under RCW 80.04.570(6)(b). In any event, PSE's argument that the Alternative Plant was available to meet the need identified in the IRP/RFP process does not hold up under the Company's own evaluation of alternatives, in which it was rejected as an option.

was selected for acquisition in conjunction with the selection of the Coal Transition PPA. This weighs strongly in favor of using the Ferndale plant cost as the measure of the per kWh price of an equivalent plant for the full capacity acquired to meet PSE's requirements through at least 2016. PSE, in contrast, would have us ignore the transaction it selected as least cost in favor of a transaction it rejected because it was not least cost and was otherwise an unsuitable option for meeting the Company's resource needs.[45] This defies logic.

43 We find that the best evidence for determining the cost of an equivalent plant for purposes of RCW 80.04.570 is the price that PSE paid for Ferndale.[46] PSE determined via the 2011 RFP process that Ferndale is the least cost electric generation plant with capacity that PSE might otherwise have obtained under the original coal transition PPA it evaluated. Although Ferndale's capacity is a bit less than the amount PSE contracted for under the Coal Transition PPA, it is easy enough to adjust for this and determine the full cost of an equivalent plant following PSE's approach. Thus, using 346 MW as the appropriate size plant, considering average deliveries of power over the life of the Coal Transition PPA, coupled with the per kilowatt price PSE paid for Ferndale (*i.e.,* $318/kW), we determine the cost of an equivalent plant is $110 million.[47]

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[45] We note in this connection that there is nothing in RCW 80.04.570 that requires the Commission to base its determination of the cost of an equivalent plant on the bid price of a plant actually available for sale at the time. It is entirely conceivable that no such plant would even exist at the time of the Commission's evaluation.

[46] In the language of property valuation, Ferndale can be regarded as a "comparable sale." The Alternative Plant bid, in contrast, represents nothing more than an offer that did not meet with acceptance in the market.

[47] The $318/kW price was calculated by PSE. *See* Exhibit No. DCG-4HC (PSE Response to Staff Data Request 2). This price includes PSE's estimated costs to effect certain plant improvements "to meet PSE's compliance and design standards," and transaction costs. Staff objects to the recognition of these costs when determining the cost of equivalent plant. *See* Exhibit DCG-1HCT at 11:11-14. We find, however, that it is appropriate to consider these costs and recognize them in making our determination.

2. Should the Rate of Return on Equity be Constant over the Life of the Contract?

44 *Commission Determination: Considering the unique ratemaking requirements imposed by RCW 80.04.570, we find that it is appropriate to accept PSE's proposal to hold the equity return component constant at PSE's currently authorized pre-tax weighted average cost of equity of 7.24 percent for the term of the Coal Transition PPA.*

45 PSE proposes that the Commission set the equity return rate at the currently authorized pre-tax weighted average 7.24 percent for the entire term of the Coal Transition PPA, regardless of what the Commission may allow as an authorized equity ratio or return on equity in future rate proceedings.[48] Mr. Garratt testifies that: "[f]or ease of calculation, this pre-tax weighted average cost of equity remains fixed throughout the term of the Coal Transition PPA."[49]

46 Mr. Gomez testifies that Staff sees no reason why the equity return rate should remain the same throughout the term of the Coal Transition PPA. He contends it should change just as PSE's authorized return on equity applicable to other assets changes from one general rate case to another.[50]

47 Mr. Garratt reiterates on rebuttal that PSE proposed to use its currently authorized pre-tax weighted average cost of equity return for the term of the Coal Transition PPA to simplify the up-front calculation of total equity return, which is required to be recovered on a levelized basis over the life of the contract. Mr. Garratt says that Staff's proposal will increase the complexity of the return calculation but "PSE can accept the proposal."[51]

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[48] This pre-tax weighted average cost of equity of 7.24% reflects the return on equity and equity ratio authorized by the Commission in PSE's most recent general rate proceeding.

[49] Exhibit No. RG-1HCT at 26:18-19.

[50] Exhibit No. DCG-1HCT at 12:4-18.

[51] Exhibit No. RG-10HCT at 34:1-2.

48 Our determination of this issue is influenced by the unique ratemaking requirements imposed by RCW 80.04.570. We are directed to allow PSE to earn return on the Coal Transition PPA based on the cost of an equivalent plant, as if PSE were acquiring a hard asset and adding it to rate base. In the case of a hard asset, PSE's capital investment would be depreciated over a fixed term and PSE is allowed to earn a return on a declining rate base at whatever rate of return on equity the Commission authorized from time to time. This is not an appropriate approach in the case of the Coal Transition PPA because most of the total equity return would be recovered during the early years of the contract, putting customers at risk in the event of early termination of the agreement. This effect is exacerbated by the short duration of the Coal Transition PPA relative to the depreciable life of an actual plant in which PSE makes an actual capital investment. We should avoid risk and uncertainty for PSE's customers who pay the costs of the Coal Transition PPA to the extent this can be accomplished.

49 It is more reasonable, then, for the Commission to determine at the outset the full amount of return PSE will be allowed to recover over the life of the Coal Transition PPA and provide for recovery of the total amount on a levelized basis over the term of the contract. This levelized return, recovered on a per MWh basis, protects customers in the event the contract is terminated early. This is PSE's approach. We find it both simple and sensible. We accordingly determine that it is appropriate in this unique situation to fix the allowed return on the Coal Transition PPA at PSE's currently authorized pre-tax weighted average cost of equity: 7.24 percent return.

50 There is a second factor to consider in this connection, though it was not addressed explicitly by the parties. This is the question of income tax effect. The 7.24 percent pre-tax weighted average cost of equity is calculated using PSE's currently authorized rate of return on equity of 9.8 percent, its currently authorized equity share in the Company's capital structure of 48 percent and the currently effective federal corporate income tax rate of 35 percent. The formula is: (9.8% x 48%)/65% = 7.24%. While we determine PSE's authorized rate of return on equity in general rate cases we have no control over the federal income tax rate. PSE is at risk if the corporate income tax rate increases. Ratepayers are at risk if it decreases. Should the corporate income tax rate change during the term of the Coal Transition PPA, the Commission may consider in an appropriate case whether the equity adder should be adjusted to reflect the new rate.

3. How Should Levelized Cost be Determined?

51 *Commission Determination: We find that PSE's method for levelizing the total equity return over the term of the contract, recognizing the net present value of the stream of payments PSE will receive if the contract runs its full term, is reasonable. We apply this method in conjunction with our $110 million equivalent plant value and determine that the cost to customers of the adder for the equity component will be $1.49/MWh.*

52 Mr. Garratt testifies that a levelized cost approach results in equal (or "levelized") payments over the applicable time period (*e.g.,* the term of a power purchase agreement or the depreciable life of a rate-based asset) and which has an equivalent present value to the present value of the stream of payments based on the traditional, front-end loaded regulatory methodology resulting from earning a fixed return upon a declining asset value.[52] Mr. Garratt says this approach was discussed with stakeholders during the legislative process that led to the coal transition provisions in Chapter 80.80 RCW and RCW 80.04.570 as a way to protect customers in the event of early termination of the Coal Transition PPA.[53]

53 According to Mr. Garratt, PSE calculated the levelized cost of the equity component of the Coal Transition PPA using its currently authorized weighted average cost of capital (*i.e.,* 7.8 percent) as its interest cost. Mr. Garratt testifies that this accounts for the time value of money using a methodology that PSE has used to levelize costs in all of PSE's requests for proposals for the past ten years.[54]

54 Staff, however, uses an interest rate of zero, effectively calculating a simple average by dividing the nominal equity amount by the time period for payments (*i.e.,* 133 months). Thus, Staff ignores the cost of deferring payments by calculating simple average cost rather than the levelized cost of the net present value.[55]

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[52] Exhibit No. RG-15T at 2:23-3:5.

[53] *Id.* at 3:8-10.

[54] *Id*. at 3:13-18

[55] *Id*. at 4:17-18.

55 Mr. Garratt, using PSE's cost equivalent plant value and fixed rate of return, demonstrates that Staff's use of a simple average cost rather than PSE's levelized cost results in a return of $2.57/MWh as compared to the $2.92/MWh result using PSE's methodology.[56] Staff's approach, applied to PSE's return calculation, would mean that the net present value of the stream of equity payments to PSE over the life of the Coal Transition PPA would be $57.39 million. This is significantly less than the $66.76 million net present value of the equity return PSE would realize from a $215 million plant depreciated over the term of the Coal Transition PPA or the $65.26 million net present value calculated using PSE's methodology.[57]

56 We determine that PSE's methodology for levelizing costs is appropriate to use. It would not be fair to PSE to ignore the time value of money in making this determination. Even though it results in PSE recovering more return on a nominal basis over the term of the Coal Transition PPA than the nominal return that would result under traditional ratemaking,[58] PSE's approach protects ratepayers by spreading the authorized return over the entire volume of power deliveries. This means that, consistent with the statutory directive,[59] customers do not bear the risks of early termination.

57 Using the method we approve, coupled with our decisions on the cost equivalent plant and equity return, results in an equity adder of $1.49 per MWh, assuming no change is required in the future due to a change in the federal corporate income tax rate. Equity payments to PSE at this level over the term of the contract have a net present

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[56] Exhibit No. RG-16 (compare Table 1 (Staff method) to Table 2 (PSE method)).

[57] *Id.* Columns B and Rows 26 of each of Tables 1 and 2 in Exhibit No. RG-16 calculate the net present value cost of the monthly equity returns calculated based on the respective levelized cost calculation methodologies. PSE's method results in a present value cost of $65.26 million, which is approximately equal to the original present value cost in Column B, line 16 of each of Tables 1 and 2 (*i.e.,* $66.76 million NPV at 7.8%). Commission Staff's methodology, however, results in a present value (Column B, line 26) of $57.39 million, which is 14% lower than the original present value cost in Column B, line 16 of each of Tables 1 and 2. *See also* Exhibit No. DCG-16CX.

[58] This is illustrated in Exhibit No. DCG-16CCX at 8.

[59] *See* RCW 82.04.570(4) (The Commission must determine that "[t]he terms of such an agreement provide adequate protection to ratepayers and the electrical company during the term of such an agreement or in the event of early termination . . ."_.

value of approximately $34.13 million.[60] The nominal value of this return over the full term of the Coal Transition PPA is about $44.12 million.

4. Should "Resupply Power" be Eligible for Equity Return?

58 *Commission Determination: We find that PSE should be allowed to recover an equity return on the full volume of power TransAlta delivers under the terms of the Coal Transition PPA, including resupply power. However, we will require PSE to monitor, and report to the Commission annually, TransAlta's production levels at the Centralia Coal Transition Facility. PSE will also be required to report whether and, if so, to what extent TransAlta has satisfied any part of its delivery obligations through the use of resupply power. The report must identify the amounts of resupply power by source. Although PSE expects TransAlta to continue to operate the plant in a manner that will result in most power delivered under the Coal Transition PPA being from the Centralia Coal Transition Facility, this is not required under the agreement. It is conceivable that deliveries from the facility will reach a point where the contract may be determined to no longer qualify under the terms of RCW 80.04.570 and related authority as a "coal transition PPA." In such unlikely circumstances, the Commission may initiate a proceeding to consider whether it remains prudent for PSE to continue taking deliveries under the contract and, if so, whether PSE can continue to recover any equity return in association with any volumes delivered under the contract.*

59 PSE's right to recover return is not tied to production from the CTCF under the terms of the Coal Transition PPA. Section 3.2 of the Coal Transition PPA allows TransAlta to provide power from any source or sources if, *for any reason*, the output from the CTCF is reduced or curtailed.[61] This is sometimes referred to as a "resupply provision," though that term is not defined in the Coal Transition PPA. Staff objects that there is nothing in the agreement that prevents TransAlta from cutting back on

[60] *See* Exhibit No. KDW-1HCT at 32:1-14.

[61] Exhibit No. RG-3C (Coal Transition PPA Section 3.2 (b) (Page 17 of 51) (*emphasis added)*

CTCF power production, delivering to PSE lower cost power from other sources,[62] and then benefiting from the price arbitrage. Mr. Woodruff testifies similarly that:

> During periods when the market prices in the PNW are below Centralia's variable operating costs, TransAlta would be expected to make the economically rational decision to reduce Centralia's output – possibly to zero – and purchase power from other sources to meet its delivery obligations under the Coal Transition PPA. During such periods, this strategy should be quite advantageous to TransAlta.[63]

In addition, Mr. Woodruff makes the point that:

> There are only weak contractual links between the operation of Centralia and the delivery and pricing terms of the Coal Transition PPA. From the perspective of PSE's customers, Centralia is barely relevant to the basic structure of the Coal Transition PPA. PSE customers will be required to purchase fixed amounts of power delivered by TransAlta for every hour from December 1, 2014, to December 31, 2025 at fixed prices regardless of whether the Centralia plant is operating. [64]

60 Staff and Public Counsel both recommend that we condition any approval of the Coal Transition PPA to address these concerns. Staff makes a specific recommendation in which Public Counsel joined during oral argument.[65] Staff argues that the equity adder should be allowed only for power generated by coal fuel at the CTCF or under Staff's proposed definition of resupply. According to Mr. Gomez:

> The proper interpretation of "resupply," as it relates to a power purchase agreement for the acquisition of coal transition power, is a

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[62] Although Staff does not say so, this might include surplus power from BPA that recent events inform us may sometimes be available on the market at no cost or even at a "negative price." Even under more ordinary conditions, it is likely that power will be available on the market from time to time at lower costs than provided under the Coal Transition CTPPA.

[63] Exhibit No. KDW-1HCT at 11:3-8.

[64] *Id.*at 7:18-8:5.

[65] Public Counsel initially recommended contract reformation to resolve this issue, but dropped that position during oral argument in favor of Staff's approach.

> seller's right to substitute the source of energy *in the event of an abnormal circumstance of limited duration that prevents delivery from the CTCF*.[66]

Mr. Gomez contends that this definition should be applied to the Coal Transition PPA to provide adequate protection to ratepayers.[67] He says, in addition, that Staff's proposal in this connection "is in keeping with the law's goal of maintaining employment in affected communities."[68]

61 Mr. Garratt does not dispute that the Coal Transition PPA allows TransAlta to obtain power from sources other than the CTCF. Focusing on the several policy goals underlying greenhouse gas emissions and coal transition legislation, however, Mr. Garratt testifies that:

> Allowing resupply upon curtailment "for any reason" promotes the public interests that the Legislature sought to promote. The Legislature found that "an electrical company's acquisition of coal transition power helps to achieve the state's greenhouse gas emission reduction goals by effecting an orderly transition to cleaner fuels and supports the state's public policy." Resupply can help reduce greenhouse gas emissions by replacing coal-fired generation with power from other sources, such as hydropower during high water periods. Resupply can also promote grid stability and reliability, and the integration of wind, solar and other variable renewable energy resources, by allowing TransAlta to reduce facility generation at times when there is excess generation present on the grid.[69]

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[66] Exhibit No. DCG-1HCT at 8:5-14 (emphasis added).

[67] *Id*. at 8:5-14. It is unclear whether relieving PSE's customers from the burden of paying the equity adder would provide adequate protection to ratepayers in circumstances where market power is available at a price lower than TransAlta's variable costs, particularly if this situation persists for significant periods of time during the contract term. During such periods, PSE's ratepayers will capture none of the benefits of the lower cost power. The Coal Transition PPA, viewed as a hedge against higher power prices, may work out to customers' benefit over its full term if such higher prices eventuate. It is also possible, however, that the power prices under the Coal Transition PPA will result in PSE's customers paying more for power than would be the case if PSE had more flexibility under the terms of the contract, or made alternative arrangements to obtain power at prices indexed in one way or another to the market.

[68] *Id.* at 13:14-19.

[69] *Id.* at 30 (quoting RCW 80.04.560). *See also* RCW 80.80.005.

62 NWEC's position supports PSE in this connection. Ms. Dixon testifies that NWEC favors having TransAlta substitute lower carbon emitting sources to meet its power delivery obligations, when feasible. Indeed, Ms. Dixon, focusing on the state's policy goal of reducing emissions, testifies the public interest would benefit if the Coal Transition PPA was amended in such a way as to "incent TransAlta to take advantage of lower GHG emitting resources while still meeting the terms of the contract."[70]

63 Making an additional point, Mr. Garratt refers to an informal opinion letter drafted by the Attorney General's Office and argues that Staff's recommendation is inconsistent with the advice it gives the Governor's Office on this question. Mr. Garratt relates that the Attorney General opined that the inclusion and exercise of resupply rights in a power purchase agreement for coal transition power does not affect the statutory right of the electrical company to recover its costs, including the equity component allowed under RCW 80.04.570(6)(a).[71]

64 We recognize that there may be times when TransAlta will not be able to provide the full volume of power required under the contract from the CTCF. During the last five years of the contract term, for example, when the single generator then operating must be shut down for maintenance, it will be necessary for TransAlta to find replacement power to meet its delivery obligations. At any time during the contract term, there may be unanticipated events that require both generators to be ramped down, or shut down, for brief periods. There may be times when it simply makes sense to shut down the two generators at the same time to conduct routine maintenance. Under these circumstances, there is a reasonable sharing of risks because TransAlta will have to obtain power for delivery to PSE regardless of whether it can do so at prices lower than the variable costs of operating the plant.

65 It would be a different matter entirely, however, if TransAlta elects to shut down production from the CTCF generators and obtain power from other sources for a significant period of time, or permanently, simply because it is financially advantageous to TransAlta to do so. PSE argues, and the weight of the evidence

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[70] Exhibit No. DOD-1-HCT at 11:14-20.

[71] Exhibit No. RG-10HCT at 27:15-28:6 (citing Exhibit No. RG-8HC at 452).

supports, that this is not a likely eventuality.[72] No one denies, however, that TransAlta could continue to meet its delivery obligations using resupply power without violating the terms of the Coal Transition PPA. Were this to occur, the contract between TransAlta and PSE could be found to have lost its status as a coal transition PPA within the meaning of RCW 80.04.570 and Chapter 80.80 RCW. This is because RCW 80.80.010(5) defines "coal transition power" to mean "the output of a coal-fired electric generation facility that is subject to an obligation to meet the standards contained in RCS 80.80.040(3)(c)."

66 The informal opinion letter from the Attorney General's office to which Mr. Garratt refers addresses this concern, recognizing that a strict reading of the statute would allow only the recovery of the output of the plant, and not resupply power. However, the informal opinion rejected that conclusion as "contrary to RCW 80.04.570 as a whole, to general principles of rate-setting, and to the purposes the Legislature identified in enacting E2SSB 5759."[73] As part of its analysis, the opinion letter notes the limited nature of resupply rights, as the opinion "assumes that, given the nature of resupply rights, such rights would be exercised *intermittently* over the multi-year term of a power purchase agreement, on an as-needed basis"[74] It observes that "the actual amounts of resupply power . . . cannot be known at the time the agreement is reviewed by the Commission."[75] Also, the opinion letter explains that while "RCW 80.04.570 does not itself address resupply rights, a related statute contemplates that power purchase agreements may involve some purchased power coming from other sources, as would occur through resupply."[76] The opinion cites RCW 80.80.040(7) which provides:

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[72] *See supra* footnote 2; Mr. Woodruff testifies, for example that TransAlta probably will not opt to meet its delivery obligations entirely without generation from the CTCF. He expects that the cost of generation from the CTCF will be less at times than wholesale electricity market prices in the Pacific Northwest. Under these circumstances, he anticipates that "TransAlta would operate Centralia at high capacity factors to provide the power needed to meet its delivery obligations under the Coal Transition PPA." Exhibit No. KDW-1HCT at 9-15. Mr. Woodruff testifies in addition that "key provisions of the PPA suggest that TransAlta views Centralia as important to its continued performance under the PPA." *Id.* at 9:16-10:3.

[73] Exhibit No. RG-8HC at 453.

[74] *Id.* at 452 (emphasis added).

[75] *Id.* at 454.

[76] *Id.*

> In no case shall a long-term financial commitment be determined to be in compliance with the greenhouse gas emissions performance standard if the commitment includes more than twelve percent of electricity from unspecified sources.

67 The opinion reasons from this provision that :

> A limit on how much power may be supplied from unspecified sources plainly contemplates that agreements may involve power being provided from sources other than the power facility entering the agreement. This would include resupply power once that right is exercised.[77]

Thus, without disputing that the Coal Transition PPA may properly include a resupply provision such as found in Section 3.2 of the agreement, or that PSE may earn equity return on resupply power, we conclude that there may be a limit under the statute on the use of such power. This interpretation is consistent with, and furthers, one of the purposes of the statute. The Legislature was clear that preservation of jobs at the plant was among those purposes. A cessation of plant operations, to the extent such a cessation would result in loss of jobs would be contrary to this purpose. By our interpretation, we seek to minimize that possibility.[78]

68 We need not at this juncture determine definitively the full legal consequences that might flow from these circumstances, if they eventuate. It is better to take a conservative and practical approach than to establish a bright line beyond which the volume of resupply power means the contract between PSE and TransAlta will lose its character as a coal transition power purchase agreement.[79] It is for this reason that we issued Bench Request No. 2, to which PSE responded on December 28, 2012.

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[77] *Id.*

[78] The Legislature found that "coal-fired baseload electric generation facilities are a significant contributor to family-wage jobs and economic health in parts of the state and that transition of these facilities must address the economic future and the preservation of jobs in affected communities." Laws of 2011, ch. 180, § 101(4).

[79] We also need not determine today the full legal consequences of such a finding. We note, however, that it could support a conclusion that PSE is no longer entitled to recover equity return on deliveries under the agreement.

The confidential information PSE provided in its response shows the Historical Generation of the CTCF in GWhs on a quarterly basis from the 1st Quarter of 2008 through the 4th Quarter of 2012, as of the time of the response. These data show that TransAlta's operations of the CTCF are consistently at a level, in all quarters of the year, that would result in all power delivered under the Coal Transition PPA being from the facility.[80] Over the five years reported, had the Coal Transition PPA been in effect, only 10 percent of the deliveries to PSE would have been considered resupply power.

69 We determine that it is necessary to condition our approval of the Coal Transition PPA in connection with this issue only to the extent of imposing a reporting requirement. This will enable the Commission to know if TransAlta exercises its resupply right to a degree that might be found to put the Coal Transition PPA in jeopardy. If Commission Staff's continuing review suggests that the contract has lost its identity as a coal transition agreement, the Commission may initiate proceedings to determine whether this is the case and, if so, what consequences flow from the determination.

B. Contract Structure and Terms

1. Should Section 10.1 of the Coal Transition PPA be Modified to Establish TransAlta as the Assumed Risk Taker in the Event of Future Greenhouse Gas Emissions Regulations or Requirements?

70 *Commission Determination: Section 10.1 of the Coal Transition PPA implements RCW 80.04.570(2) using largely the terms of the statute itself. We reject NWEC's recommendation that we require the PSE and TransAlta to reopen their negotiations and modify the contract to reflect NWEC's policy position, which in this instance is contrary to what the statute provides.*

[80] Section 3.2 of the Coal Transition PPA effectively provides that TransAlta will "supply the Hourly Contract Quantity from the CTCF" unless "the output of the CTCF is reduced or curtailed."

71 NWEC is concerned Section 10.1 of the Coal Transition PPA, which implements RCW 80.04.570(2).[81] Employing the language of the statute, Section 10.1 provides that if new or revised emission performance standards or operational or financial requirements related to greenhouse gas emissions are imposed by law, PSE and TransAlta will initiate a process to modify the agreement to their mutual satisfaction. Any such agreement is subject to Commission review and approval, as expressly required by the statute. Finally, as provided in RCW 80.04.570(2), if PSE and TransAlta cannot agree, either party has the right to terminate the Coal Transition PPA without liability, if the party is adversely affected by the new standard or requirement.

72 Ms. Dixon testifies that NWEC does not support the Coal Transition PPA provisions as written. NWEC's position is that TransAlta should absorb the risk of future GHG emissions regulations. Ms. Dixon says the Coal Transition PPA could establish TransAlta as the assumed risk taker in the event of future greenhouse gas emissions regulations or requirements, while still allowing for a contract reopener at the time of any such regulations or requirements to assess specific details, if needed.

73 It is not entirely clear what NWEC is proposing, but it appears to be that we condition approval of the Coal Transition PPA by requiring the parties to reopen their negotiations now and somehow agree to place the risk of future greenhouse gas emissions requirements on TransAlta. This would, in Ms. Dixon's concept,

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[81] RCW 80.04.570(2) reads:

> Any power purchase agreement for the acquisition of coal transition power pursuant to this section must provide for modification of the power purchase agreement to the satisfaction of the parties thereto in the event that a new or revised emission or performance standard or other new or revised operational or financial requirement or limitation directly or indirectly addressing greenhouse gas emissions is imposed by state or federal law, rules, or regulatory requirements. Such a modification to a power purchase agreement agreed to by the parties must be reviewed and considered for approval by the commission, considering the circumstances existing at the time of such a review, under procedures and standards set forth in this section. In the event the parties cannot agree to modification of the power purchase agreement, either party to the agreement has the right to terminate the agreement if it is adversely affected by this new standard, requirement, or limitation.

"internalize the cost of environmental harm into the cost of [the] product."[82] She acknowledges that if TransAlta assumes the risk of future GHG regulations, the agreed upon power price terms could change.

74 PSE does not address this issue in its rebuttal testimony.

75 As we stated at the beginning of this discussion, Section 10.1 of the Coal Transition PPA tracks very closely the language of the statutory provision that requires it. It is difficult to conceive how PSE and TransAlta could modify Section 10.1 along the lines NWEC suggests without running afoul of what the legislature intended by drafting RCW 80.04.570(2) using the language it chose. In particular, requiring TransAlta to expressly assume the risk of a change in greenhouse gas emission standards would seem to eliminate any claim by TransAlta that it is adversely affected by the change. Thus, TransAlta would not be able to exercise its right, expressly conferred by the statute, to terminate the Coal Transition PPA without liability "if adversely affected by the new standard or requirement, or limitation."[83]

76 The conflict between NWEC's proposal and the requirements of RCW 80.04.570(2), which Section 10.1 of the Coal Transition PPA implements, is reason enough to reject it. In addition, however, we cannot square NWEC's tacit acknowledgement that power prices under the Coal Transition PPA would likely increase if we effectively require TransAlta to internalize now the costs of possibly more stringent environmental regulations in the future, with NWEC's claim that this somehow protects "the interest of PSE customers in avoiding future risk of GHG emissions."[84] Quite the contrary is true. Higher prices under the Coal Transition PPA would simply pass on to ratepayers for the full term of the contract the increased risks TransAlta would assume relative to a change in the law that may or may not occur during its term. We reject NWEC's recommendation.

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[82] Exhibit No. DOD-1HCT at 11:2. Ms. Dixon testifies in addition that modifying Section 10.1 of the Coal Transition PPA as NWEC recommends "could incent TransAlta to take advantage of lower GHG emitting resources while still meeting the terms of the contract." *Id.* at 11:14-20. The specific contract term to which Ms. Dixon refers is Section 3.2, the provision Staff is concerned about in connection with its proposed treatment of "resupply power."

[83] RCW 80.04.570(2).

[84] Exhibit No. DOD-1HCT at 10:19-11:13.

C. Relationship Between the Coal Transition PPA and TransAlta's Performance under the MOA

77 *Commission Determination: We conclude as a matter of law that if TransAlta terminates the MOA prior to the time PSE begins taking power in December 2014, or subsequently, PSE is not relieved of its obligations under the contract.*[85] *Thus, we reject Staff's proposal that we deem the PPA be terminated if the MOA is terminated. We also conclude that the Commission lacks authority to effectively modify the terms of the MOA, as NWEC urges us to do.*

78 *We also determine in this connection, however, that if TransAlta terminates the MOA under Section 8(c), or the MOA is terminated or cancelled by the State of Washington as a result of a failure by TransAlta to satisfy its payment obligations under Section 3 of the MOA the Commission should initiate proceedings to consider whether to require PSE to terminate the Coal Transition PPA to the extent it may do so without incurring liability. Finally, if the MOA is terminated at any time during the term of the Coal Transition PPA, for any other reason, the Commission may initiate proceedings to determine whether the contract retains its identity as a coal transition PPA under RCW 80.04.570 and related authority, and whether PSE should be authorized to continue to recover equity return as authorized under RCW 80.04.570(6).*

79 Staff recommends that the Commission condition its approval of the Coal Transition PPA by requiring that it will terminate if the MOA is terminated. Given its brevity, we quote below Mr. Gomez's entire discussion of this recommendation:

> The MOA specifies the obligations required from each party as a result of the Coal Transition Energy Bill, E2SSB 5769. These obligations include annual payments by TransAlta totaling $55.0 million to fund economic and community development in Lewis and South Thurston

[85] Section 9(d) of the MOA provides: "Termination of this MOA pursuant to Section 8 shall not in any manner impact the validity or enforceability of contracts or agreements entered into by the Parties, other than this MOA, prior to the date of such termination, including Qualified Power Purchase Agreements or other agreements for the sale of electrical output of the Facility."

> County. Staff views PSE ratepayers, via the Coal Transition PPA, as a main source of these funds.[86]

80 Ms. Dixon testifies for NWEC that TransAlta's commitment to invest in local economic development and clean energy was a critical element of the negotiations that led to amending the emissions performance standard for coal transition power.[87] This is substantiated, she says, by a legislative finding in ESSB 5769, Sec. 101(4):

> The legislature finds that coal-fired baseload electric generation facilities are a significant contributor to family-wage jobs and economic health in parts of the state and that transition of these facilities must address the economic future and the preservation of jobs in affected communities.

81 Ms. Dixon testifies that the law and the MOA provide both time and funding to help the community succeed in its transition away from operating a coal-fired power plant, which will mean the loss of certain family-wage jobs. Providing educational and retraining opportunities for local workers is a critical piece of ensuring an orderly transition, in NWEC's view. At the same time, dedication of funds to energy efficiency and clean energy technologies will help create new good-paying "green jobs" while providing a path to cleaner power.

82 Ms. Dixon says NWEC's concerns in this area stem from the fact that TransAlta's financial commitments are not assured under the statute or the MOA. RCW 80.80.100(3)(c), for example, provides that the TransAlta is relieved of its obligations if certain tax exemptions currently available to the Centralia coal plant are repealed. In addition, the MOA includes a termination clause that TransAlta can invoke if it fails by December 15, 2013,[88] to execute sufficient long-term coal transition PPAs to

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[86] Exhibit No. DCG-1HCT at 16:9-14.

[87] The MOA provides for $20 million to the affected community for education, retraining, economic development, and community enhancement; $10 million to the affected community for energy efficiency and weatherization; and $25 million for energy technologies with the potential to create considerable energy, economic development, and air quality, haze, or other environmental benefits. *See* Exhibit No. RG-8HC at 2-3 (MOA Section 3).

[88] TransAlta's initial opportunity to terminate the MOA under this provision matured on December 15, 2012, but TransAlta elected to extend the deadline by one year, as allowed under the terms of the agreement.

sell at least 500 MWs of output from the Centralia facility. Because the average volume of power to be delivered to PSE during the term of the Coal Transition PPA is only 346 MW, Commission approval would not preclude TransAlta from invoking its termination rights under the MOA.

83 Even though PSE may terminate the PPA in this circumstance, NWEC is concerned that PSE could decide to continue the Coal Transition PPA without modification even if the MOA ceases.[89] The end result would be that the local community may see no financial support to facilitate the transition to a new economic base.

84 In light of these concerns, NWEC recommends that the Commission condition approval of the Coal Transition PPA by making it contingent on TransAlta committing to invest in at least the proportional level of funding outlined in the MOA that is represented by PSE's acquisition of 346 MW of output. This would provide certainty that at least $13.8 million is invested in local economic development, $6.9 million is invested in energy efficiency and weatherization, and $17.3 million is invested in clean energy technologies. Ms. Dixon testifies that the requirement for financial assistance is part and parcel of the modifications to the emissions performance standard that are allowing PSE to enter into the Coal Transition PPA and it should be a factor in the Commission's determination of public interest.

85 Mr. Garratt points out in rebuttal that neither PSE nor the Commission is a party to the Memorandum of Agreement. He states that "PSE does not know what role, if any, the Commission should play with respect to a contract in which neither PSE nor the Commission is a party."[90] Responding more directly to Staff's recommendation, Mr. Garratt offers two reasons that militate against the Staff's proposal to condition approval of the Coal Transition PPA by requiring that it terminates if the MOA is terminated. First, he relates that TransAlta Centralia can terminate the MOA for reasons unrelated to power sales under the Coal Transition PPA. He cites two examples; TransAlta may terminate the Coal Transition PPA if:

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[89] *See* Exhibit No. RG-10HCT at 40:12-41:6; *See also* Exhibit No. RG-3C at 34 (Coal Transition PPA Section 17.3).

[90] Exhibit No. RG-10HCT at 39:5-8.

- It loses its state sales and use tax exemptions currently available under RCW 82.08.811 and RCW 82.12.811.

- It is not allowed to use the type of air pollution control equipment to which the State of Washington agreed in the MOA.

The MOA, in Mr. Garratt's view, appears to recognize that TransAlta would lose the benefit of its bargain with the State or Washington if either of these things occur and should not have to continue paying the $55 million for promotion of the state's policies.[91]

86 Mr. Garratt testifies also that TransAlta has the right to terminate the MOA if it has not been able to enter into long-term power purchase agreements for at least 500 megawatts of power by December 15, 2012. TransAlta Centralia has informed Governor Gregoire, however, that it will not exercise this option in 2012.[92] However, the effect of this is to extend the MOA for one year, at which time TransAlta again has the option to terminate it. Should this occur during 2013, Mr. Garratt testifies that:

> It is in the best interest of PSE's ratepayers that PSE have the right to decide whether to terminate under these circumstances. If purchases under the Coal Transition PPA remain the most cost-effective resource available, PSE may well decide that, notwithstanding termination of the Memorandum of Agreement, it is in the best interest of ratepayers to continue to make purchases under the Coal Transition PPA.[93]

Thus, PSE would have the Commission reject Staff's recommendation that the Coal Transition PPA be terminated if the MOA is terminated.

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[91] Id. at 39-40.

[92] *See* Exhibit No. RG-14 (letter dated October 24, 2012, from Paul Taylor to Governor Gregoire). The letter states that TransAlta has not yet achieved the 500 MW contracting threshold contemplated in the MOA.

[93] Exhibit No. RG-10HCT at 41:1-6.

87 Although we agree with the policy principles that underlie Staff's and NWEC's advocacy on this issue,[94] we are constrained by the law from accepting their specific recommendations. Insofar as Staff's recommendation is concerned, what we have before us today is a "power purchase agreement for acquisition of coal transition power" within the meaning of RCW 80.04.570. The Coal Transition PPA also is a "Qualified Power Purchase Agreement" as defined in the MOA. As previously noted, Section 9(d) of the MOA provides:

> Termination of this MOA pursuant to Section 8 shall not in any manner impact the validity or enforceability of contracts or agreements entered into by the Parties, other than this MOA, prior to the date of such termination, including Qualified Power Purchase Agreements or other agreements for the sale of electrical output of the Facility.

Because the Coal Transition PPA is a Qualified Power Purchase or other agreement for the sale of electrical output of the CTCF, termination of the MOA cannot be the basis for terminating the PPA except to the extent PSE reserved its rights to do so and elects to exercise them.[95]

88 Insofar as NWEC's recommendations are concerned, they would require us to effectively add provisions to the MOA that are inconsistent with RCW 80.80.100. We are not empowered to do this. Not only is the Commission not a party to the MOA, there is nothing in the MOA, or the applicable statutes, that gives the Commission any express or implied authority to alter this bilateral agreement.

89 Having reached these conclusions, however, we nevertheless conclude that the MOA is an important, if not essential, feature in the legal and policy landscape that gives rise to the very concept of "coal transition power." Absent the amendment of RCW Chapter 80.80 by the Coal Transition Energy Bill during 2011, the contract before us could not have been executed by TransAlta and PSE; there would be no Coal

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[94] We understand this principle to be that the MOA and any agreement for the sale and purchase of coal transition power are so inextricably intertwined that the one should not exist in the absence of the other. The very concept of "coal transition power" depends in significant part on TransAlta's performance under the MOA that provides the funds for the transition.

[95] We note in this connection that the Commission, in a subsequent proceeding, could open the question whether it would be imprudent for PSE to not exercise these rights should the opportunity present itself.

Transition PPA, and we would not be reviewing the contract at all, much less under the special requirements of RCW 80.04.570.

90 RCW 80.80.100 requires the MOA. The statute provides that the MOA may only include the provisions specified in RCW 80.80.100. It sets forth these provisions in detail, including definitive requirements that the facility owner provide two forms of financial support as the coal plant is transitioned into closure:

- $30 million in financial assistance for economic development and energy efficiency and weatherization to the affected community.[96]

- $25 million for energy technologies with the potential to create considerable energy, economic development, and air quality, haze, or other environmental benefits.[97]

These financial benefits specified in the legislation provide an important part of the *quid pro quo* to which TransAlta agreed during negotiation of the MOA in exchange for the right to enter into long-term contracts for the sale of power from the Centralia coal facility even though the plant does not physically meet the state's emission performance standards, and will not do so during the remainder of its operation.

91 The legislature provided an additional benefit to TransAlta by providing an unprecedented inducement to investor-owned utilities such as PSE to enter into such contracts. We refer specifically to the provision included in RCW 80.04.570(6) that requires the Commission to allow such utilities to recover from their customers not only the cost of power provided under a coal transition PPA, but also to recover equity return as if the utility made a capital investment in a hard asset instead of simply entering into a power purchase agreement that requires no such investment.

92 Thus, we see the MOA, RCW Chapter 80.80 and RCW 80.04.570 as three intertwined elements that together establish the concept of coal transition power and define the rights and obligations of TransAlta, PSE and, most important, the people of

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[96] RCW 80.80.100(3).

[97] *Id.*

Washington. The fulfillment of these rights and obligations provides a transition for TransAlta, allowing for an orderly and financially satisfactory retirement of the Centralia coal facility. The fulfillment of these rights and obligations provides a transition for citizens living in the communities most directly affected by the closure, maintaining family-wage jobs and promoting economic development that will substitute for the loss of the plant, which remains an economic mainstay in Centralia and surrounding suburban and rural communities. Finally, it is by the fulfillment of these rights and obligations that the state has provided for the broader public interest to benefit from the assured closure of a significant source of air pollution on a definite schedule.

93 It is true that the MOA and RCW Chapter 80.80 allow for the termination of certain of these mutual rights and obligations upon the occurrence of specified events. We cannot foresee whether any of these events will occur, or evaluate in the abstract the impact any such occurrence relative to the Commission's obligation to "[r]egulate in the public interest, as provided by the public service laws, the rates, services, facilities, and practices of all persons engaging within this state in the business of supplying any utility service or commodity to the public for compensation."[98] We determine, however, that significant changes in circumstances such as a decision by TransAlta to terminate the MOA, or its failure to meet its financial obligations under the MOA as contemplated under RCW 80.80.100, may require a reexamination of the contract between TransAlta and PSE. Should the contract be found under some set of circumstances to have lost its character, and its legal status, as a coal transition PPA, it may be incumbent upon the Commission to initiate proceedings to review the contract and, among other things, consider whether PSE can continue to earn the equity return allowed here, as provided only for a coal transition agreement under RCW 80.04.570.

D. Cost Deferral

94 *Commission Determination: The Commission determines that the question whether PSE should be authorized to defer the incremental costs it incurs as volume and price terms vary from time to time during the life of the Coal Transition PPA should be*

[98] RCW 80.01.040.

reserved for decision during a rate proceeding in which PSE seeks to recover its initial costs under the Coal Transition PPA, beginning in December 2014.

95 PSE seeks to defer both the contracted purchase price and the costs of the equity return associated with the Coal Transition PPA prior to those costs being included in rates. Additionally, PSE seeks to accrue interest on the deferred amounts, at PSE's net of tax rate of return for the period, currently 6.71 percent. A similar deferral would be used to adjust the yearly increases in contracted power and price increases in the Coal Transition PPA. Ms. Barnard testifies for PSE that:

> PSE would not start booking these deferrals until December 2014 when the contracted volumes begin to flow. A deferral will continue until the date when new rates that address the costs being deferred take effect, and this deferral process will continue throughout the term of the Coal Transition PPA as volumes and prices change in accordance with the terms of the Coal Transition PPA.[99]

96 Staff objects to PSE's proposal to defer costs. Mr. Gomez testifies that this situation is not one such as Goldendale, where PSE had limited control over the timing of the acquisition and was required to immediately borrow the large amount of funds necessary to secure the Goldendale Generating Station opportunity for its customers well in advance of enabling recovery methods. Here, PSE will not take its first delivery of power for nearly two years. This, according to Staff, provides the Company with sufficient time to include the Coal Transition PPA into rates via a Power Cost Only Rate Case (PCORC). Staff does not address specifically the question of deferrals PSE proposes during the term of the Coal Transition PPA as prices and volumes change from year to year.

97 Ms. Barnard focuses on this point in her rebuttal. She testifies that PSE cannot time a general rate case or PCORC filing perfectly to address changes in costs with the Coal Transition PPA that occur throughout its term. Ms. Barnard reiterates the point made in her direct testimony that what PSE proposes to defer are its incremental costs associated with the Coal Transition PPA that are not included in rates.[100] While these

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[99] Exhibit No. KJB-1T at 5:8-12.

[100] Exhibit No. KJB-3T at 3:2-4.

costs change from year to year, the time required to process a general rate case, or even a PCORC, means it is necessary for PSE to maintain a deferral account for these costs or it may lose the opportunity to recover them.

98 PSE acknowledges that it can time the filing of a general rate case or a PCORC so that the costs of the Coal Transition PPA beginning on December 1, 2014, could be recovered in rates.[101] PSE argues, however, that during the subsequent course of the contract, as TransAlta's delivery obligations change from time to time and the power price changes from year to year, it would become difficult to time PCORC and general rate proceedings to include the incremental costs associated with these changes, as they occur. PSE argues that without the authority to defer these costs, the Company would be at risk for losing its ability to recover them. PSE believes this problem would be most significant in the years when the volumes change.[102]

99 As a general matter, it is more appropriate to consider the question of deferral accounting in the context of a rate proceeding. There is ample time for PSE to initiate such a proceeding before the time it begins taking power under this contract in December 2014. We accordingly determine that the Commission will await PSE's initial filing to recover its costs under the Coal Transition PPA to determine this issue.

FINDINGS OF FACT

100 Having discussed above the evidence received in this proceeding concerning all material matters, the Commission now makes and enters the following summary of facts, incorporating by reference pertinent portions of the preceding detailed findings:[103]

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[101] PSE's counsel agreed during oral argument that this is the case: "I believe that PSE probably does not see a need necessarily to defer the first tranche of the agreement, because they will have two years to prepare for that." TR. 255:7-10 (Kuzma).

[102] *Id*. at 225:18-21.

[103] We recognize that certain findings of fact and conclusions of law are mixed findings and conclusions, including findings 2, 4, 5 and 6. In light of their significance relative to the specific statutes governing our review of the Coal Transition PPA, we underscore this point by repeating findings 4, 5 and 6 in the conclusions of law section of this Order.

101 (1) The Washington Utilities and Transportation Commission is an agency of the State of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including electrical companies.

102 (2) Puget Sound Energy, Inc., (PSE) is a "public service company" and an "electrical company," as those terms are defined in RCW 80.04.010 and as those terms otherwise are used in Title 80 RCW. PSE is engaged in Washington State in the business of supplying utility services and commodities to the public for compensation.

103 (3) On July 24, 2012, PSE and TransAlta Centralia entered into the Coal Transition PPA that is the subject of this proceeding. It provides that PSE will purchase up to 380 MW of coal transition power, with average deliveries over the life of the contract, through 2025, of 346 MW.

104 (4) Considering the circumstances existing at the time of the Commission's review, the terms of the Coal Transition PPA provide adequate protection to ratepayers and PSE during the term of the Coal Transition Power PPA or in the event of early termination.

105 (5) PSE needs the Coal Transition PPA to serve its ratepayers and the resource meets this need in a cost-effective manner as determined under the lowest reasonable cost resource standards under chapter 19.280 RCW, including the cost of the Coal Transition Power PPA plus the equity component as determined in RCW 80.04.570.

106 (6) The Coal Transition PPA includes termination dates consistent with the applicable dates in RCW 80.80.040(3)(c).

107 (7) The cost of an equivalent plant for purposes of determining the equity return component for the Coal Transition PPA is $110 million, which is a total equivalent plant cost for the Coal Transition PPA of a plant of approximately 346 MW.

CONCLUSIONS OF LAW

108 Having discussed above all matters material to this decision, and having stated detailed findings, conclusions, and the reasons therefore, the Commission now makes the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

109 (1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and parties to, this proceeding.

110 (2) The Coal Transition PPA is a long-term financial commitment for the purchase of coal transition power, as such terms are defined in RCW 80.80.010(16) and RCW 80.80.010(5), respectively, and as such terms are otherwise used in Title 80 RCW.

111 (3) The Coal Transition PPA is a power purchase agreement for acquisition of coal transition power, subject to the Commission's review and authority under RCW 80.04.570 and as otherwise provided in RCW Chapter 80.80.

112 (4) Considering the circumstances existing at the time of the Commission's review, the terms of the Coal Transition PPA provide adequate protection to ratepayers and PSE during the term of the Coal Transition Power PPA or in the event of early termination

113 (5) PSE needs the Coal Transition PPA to serve its ratepayers and the resource meets this need in a cost-effective manner as determined under the lowest reasonable cost resource standards under chapter 19.280 RCW, including the cost of the Coal Transition Power PPA plus the equity component as determined in RCW 80.04.570.

114 (6) The Coal Transition PPA includes termination dates consistent with the applicable dates in RCW 80.80.040(3)(c).

115 (7) As required under RCW 80.04.570(2), the Coal Transition PPA provides for modification of its terms to the mutual satisfaction of the parties, if a new or revised emission or performance standard or other new or revised operational

or financial requirement or limitation directly or indirectly addressing greenhouse gas emissions is imposed by state or federal law, rules, or regulatory requirements. Under the Coal Transition PPA, such a modification must be consistent with RCW 80.04.570 and is subject to review and approval by the Commission. If the parties cannot agree to modification of the Coal Transition PPA, either party has the right to terminate the Coal Transition Power PPA if such party is adversely affected by the new standard, requirement, or limitation as described in RCW 80.04.570(2).

116 (8) PSE must be authorized to earn the equity component of its authorized rate of return as provided in RCW 80.04.570(6). The rate of return should be fixed throughout the term of the Coal Transition PPA at the Company's currently authorized pre-tax weighted average cost of equity of 7.24 percent, subject to possible adjustment if there is a change in the federal corporate income tax rate.

117 (9) The equivalent plant cost of $110 million, as determined by the Commission to be the least cost purchased or self-built electric generation plant with equivalent capacity, must be amortized over the life of the power purchase agreement for acquisition of coal transition power, which is the term of the Coal Transition PPA (commencing on December 1, 2014, and expiring on December 31, 2025) to determine the recovery of the equity value. Assuming no change in the federal corporate income tax rate, the equity component of PSE's authorized rate of return for the Coal Transition PPA will be earned by PSE and recovered, in an amount equal to $1.49/MWh for each MWh of energy paid for by PSE under the Coal Transition PPA, throughout its term regardless of whether the term of the Coal Transition PPA terminates upon its expiration or is terminated prior to its expiration.

118 (10) The approved recovery of PSE's costs incurred under the Coal Transition PPA should consist of two separate expenses, as proposed by PSE:

- TransAlta Centralia will bill the cost per MWh of energy, and PSE will record this expense in FERC Account 555, Purchase Power. PSE will *pro form* this cost into power costs in the same manner as PSE *pro forms* costs associated with other power purchase agreements and treat this cost in the

Company's Power Cost Adjustment (PCA) mechanism in the same manner PSE treats costs associated with other power purchase agreements.

- PSE will *pro form* the equity return cost per MWh into power costs in general rate case filings. PSE will account for the costs associated with the equity return component on Schedule B-1 of the PCA mechanism.

119 (11) PSE's entry into the Coal Transition PPA is prudent and the associated costs are reasonable for recovery in rates, subject to a future prudence review of PSE's actual power costs as provided in Paragraph 4 of the PCA Settlement Agreement approved in Dockets UE-011570 and UG-011571.

120 (12) The Commission's continuing obligation to regulate in the public interest, as provided by the public service laws, requires the Commission to impose on PSE a reporting requirement so that the Commission can be kept apprised of the operation of the Coal Transition PPA within the legal and policy framework discussed in the body of this Order. PSE should be required to work with Commission Staff to determine the specific form and requirements for an annual report that will include, at a minimum, detailed information on a quarterly basis concerning the operations of Centralia coal transition facility and the sources of power used by TransAlta to fulfill its delivery obligations to PSE. The report also should include data concerning the payments TransAlta makes under the terms of the MOA and a description of the uses to which these funds are dedicated.

121 (13) Commission approval of the Coal Transition PPA, subject to the conditions and requirements of this Order, is in the public interest.

ORDER

THE COMMISSION ORDERS THAT:

122 (1) The Coal Transition Power Purchase Agreement between TransAlta Centralia Generation LLC and Puget Sound Energy, Inc., is approved consistent with and subject to the determination of issues as discussed in the body of this Order.

123 (2) The equity component of PSE's authorized rate of return for the Coal Transition PPA will be earned by PSE and recovered, in an amount equal to $1.49/MWh for each MWh of energy paid for by PSE under the Coal Transition PPA, throughout its term regardless of whether the term of the Coal Transition PPA terminates upon its expiration or is terminated prior to its expiration, subject to possible revision if the federal corporate income tax rate is changed during the term of the contract.

124 (3) PSE's costs under the Coal Transition PPA, as determined in this Order, are reasonable for recovery in rates, subject to a future prudence review of PSE's actual power costs as provided in Paragraph 4 of the PCA Settlement Agreement approved in Dockets UE-011570 and UG-011571.

125 (4) The approved recovery of PSE's costs incurred under the Coal Transition PPA will consist of two separate expenses, as proposed by PSE:

- TransAlta Centralia will bill the cost per MWh of energy, and PSE will record this expense in FERC Account 555, Purchase Power. PSE will *pro form* this cost into power costs in the same manner as PSE *pro forms* costs associated with other power purchase agreements and treat this cost in the Company's Power Cost Adjustment (PCA) mechanism in the same manner PSE treats costs associated with other power purchase agreements.

- PSE will *pro form* the equity return cost per MWh into power costs in general rate case filings. PSE will account for the costs associated with the equity return component on Schedule B-1 of the PCA mechanism.

126 (5) The Commission's approval is subject to the condition that Puget Sound Energy, Inc., within 30 days after the date of this Order, will enter into good faith discussions and determine in coordination with Commission Staff the content and form of an annual report that will be filed with the Commission under Docket UE-121373, as provided under WAC 480-07-880(3). The report should include monthly data for the preceding 13 months beginning with the period December 1, 2014, through December 31, 2014, and must be provided no later than March 31 of each year, beginning in 2015. The report must include data that show plant operations and the sources of power from which TransAlta satisfies its delivery obligations to PSE under the Coal Transition

PPA, and information concerning the payments and disposition of payments as required under the Memorandum of Agreement between the Governor's Office and TransAlta Centralia entered into on December 23, 2011, memorializing in contractual form the requirements set forth in the Coal Transition Energy Bill, as codified in RCW 80.80.100. The report should include such other data as agreed between Commission Staff and Puget Sound Energy, Inc. These parties should file a detailed description of the report they propose within 120 days after the date of this Order. The proposed content and form of the report is subject to approval by the Commission's Executive Director and Secretary to whom the Commission delegates this responsibility.

127 (6) The Commission retains jurisdiction to effectuate the terms of this Final Order.

Dated at Olympia, Washington, and effective January 9, 2013.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION[104]

JEFFREY D. GOLTZ, Chairman

PATRICK J. OSHIE, Commissioner

PHILIP B. JONES, Commissioner

[104] On January 7, 2013, pursuant to her authority under RCW 80.01.035, Governor Christine Gregoire appointed former Commissioner Patrick J. Oshie, who resigned from office effective January 6, 2013, as Commissioner Pro Tempore for purposes of completing and signing this Final Order.

NOTICE TO PARTIES: This is a Commission Final Order. 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 and WAC 480-07-870.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-109:
Centralia Conversion Announcement

Source: *TransAlta Corporation*

December 09, 2025 07:00 ET

TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion

CALGARY, Alberta, Dec. 09, 2025 (GLOBE NEWSWIRE) --

Highlights

- TransAlta to perform coal-to-gas conversion on its Centralia Unit 2 facility in Washington state, with a planned contracted capacity of 700 MW
- The converted facility will deliver reliable power to Puget Sound Energy under a long-term, 16-year fixed price contract through Dec. 31, 2044
- The project is currently projected to deliver a build multiple[1] of approximately 5.5 times
- The converted facility maintains TransAlta's position in its strategic core jurisdiction of the Pacific Northwest and extends the life of one of its legacy assets

TransAlta Corporation (TransAlta or the Company) (TSX: TA) (NYSE: TAC) is pleased to announce that it has signed a long-term tolling agreement (the Agreement) with Puget Sound Energy, Inc. (PSE) to convert its Centralia Unit 2 facility from coal to natural gas-fired generation. The Agreement provides a fixed-price capacity payment that provides PSE the exclusive right to the capacity, energy and ancillary service attributes of, as well as the dispatch rights to, the 700 MW facility.

"Our Centralia facility has a long history of providing reliable and affordable power in the Pacific Northwest region. We are pleased to extend the useful life of this asset and support the ongoing reliability needs of PSE and, by extension, its customers" said John Kousinioris, President and Chief Executive Officer.

"The facility is scheduled to cease coal-fired generation at the end of 2025, and the conversion to natural gas will lower the emission intensity profile of the facility by approximately 50 per cent. We are grateful for the constructive and solution-oriented engagement we have received from the Department of Ecology and other state and local regulatory bodies through the development of this project and we are well positioned to receive required regulatory approvals in a timely manner. This project demonstrates the valuable role that legacy assets can play in supporting the State's

clean energy laws and system reliability in a cost effective and timely fashion," added Mr. Kousinioris.

"When the facility re-enters operations, it will generate long-term contracted cash flow for TransAlta, earning a full return on and of capital within the contract term. The Company is well positioned to execute this project given our deep technical, operational and engineering experience gained in previous coal-to-gas conversions," concluded Mr. Kousinioris.

Approximately US$600 million of capital expenditures will be required to extend the useful life of the facility and convert it from coal to natural gas-fired generation, delivering an anticipated build multiple[1] of approximately 5.5 times. The target commercial operation date is late-2028 and the facility will operate until the end of 2044 under the terms of the Agreement. TransAlta anticipates declaring a final investment decision (FID) after receipt of all required approvals in early 2027. The Agreement is subject to customary regulatory approvals, including PSE receiving satisfactory approval from the Washington Utilities and Transportation Commission.

[1] Build multiple is a non-IFRS ratio which is calculated using capital expenditures and adjusted EBITDA[2]. We believe build multiple provides investors with a useful measure to evaluate capital projects. Readers are cautioned that our method for calculating build multiple may differ from methods used by other entities. Therefore, it may not be comparable to similar measures presented by other entities.

[2] Adjusted EBITDA is a non-IFRS measure. It does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Adjusted EBITDA is calculated by adjusting earnings before income taxes for certain items that may not be reflective of ongoing business performance. Please refer to the “Non-IFRS and Supplementary Financial Measures” section of our management’s discussion and analysis for the three and nine months ended September 30, 2025 (“MD&A”) for more information about the non-IFRS measures we use, including a reconciliation of adjusted EBITDA to earnings before income tax, the most directly comparable IFRS measure, which section of the MD&A is incorporated by reference herein. The MD&A can be found on SEDAR+ (www.sedarplus.ca) under TransAlta’s profile.

About TransAlta Corporation:
TransAlta owns, operates and develops a diverse fleet of electrical power generation assets in Canada, the United States and Australia with a focus on long-term shareholder value. TransAlta provides municipalities, medium and large industries, businesses and utility customers with affordable, energy efficient and reliable power. Today, TransAlta is one of Canada’s largest producers of wind power and Alberta’s largest producer of thermal generation and hydro-electric power. For over 114 years, TransAlta has been a responsible operator and a proud member of the communities where we operate and where our employees work and live. TransAlta aligns its corporate goals with the UN Sustainable Development Goals and the Future-Fit Business Benchmark, which also defines sustainable goals for businesses. Our reporting on climate change management has been guided by the International Financial Reporting Standards (IFRS) S2 Climate-related Disclosures Standard and the Task Force on Climate-related Financial Disclosures (TCFD) recommendations. TransAlta has achieved a 70 per cent reduction in GHG emissions or 22.7 million tonnes CO2e since 2015 and received an upgraded MSCI ESG rating of AA.

For more information about TransAlta, visit our web site at transalta.com.

Cautionary Statement Regarding Forward-Looking Information
This news release includes “forward-looking information,” within the meaning of applicable Canadian securities laws, and “forward-looking statements,” within the meaning of applicable United States securities laws, including the Private Securities Litigation Reform Act of 1995 (collectively referred to herein as “forward-looking statements”). Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as “may”, “will”, “believe”, “expect”, “estimate”, “anticipate”, “intend”, “plan”, “forecast”, “continue” or other similar words. In particular, this news release contains forward-looking statements about the following, among other things: contracted capacity of 700MW; build multiple; the facility's emission intensity profile; receipt of required regulatory approvals in a timely manner; expected capital expenditure; the target commercial operation date and the timing of a final investment decision with respect to the conversion.

Forward-looking statements and future-oriented financial information in this news release are intended to provide the reader information about management's current expectations and plans and readers are cautioned that such information may not be appropriate for other purposes. Forward-looking statements are subject to important risks and uncertainties and are based on certain key assumptions. All forward-looking statements reflect TransAlta's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. As actual results could vary significantly from the forward-looking statements, you should not put undue reliance on forward-looking statements and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events, unless we are required to by law. For additional information on the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, refer to our most recent MD&A and the 2024 Integrated Report, including the section titled "Governance and Risk Management" in our MD&A for the year ended December 31, 2024, filed under TransAlta's profile on SEDAR+ at www.sedarplus.ca and with the U.S. Securities and Exchange Commission at www.sec.gov.

Note: All financial figures are in Canadian dollars unless otherwise indicated.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-110:
Centralia Conversion Reporting

Washington State Standard

Washington's last coal power plant will transition to natural gas

The facility was set to close this year. A deal announced Tuesday will keep it producing electricity.

BY: **JOSEPH O'SULLIVAN** - DECEMBER 9, 2025 3:21 PM



An undated aerial view of TransAlta's coal-fired power plant in Centralia, Washington. (Photo courtesy of Washington Department of Ecology)

TransAlta Corporation has signed an agreement with Puget Sound Energy to switch the last coal-fired power station in Washington state to natural gas.

The deal, which TransAlta announced Tuesday, comes as the Centralia plant is set to fall silent at the end of the month.

Its closure is part of a deal the Washington Legislature approved in 2011. The winding down of the last coal-fired unit represents a long-sought goal for Democratic state politicians: the move toward cleaner energy to reduce fossil-fuel emissions and combat climate change.

But it also comes amid rising concerns that the state could face a power crunch as it makes that transition.

In a statement, John Kousinioris, president and chief executive officer of the Canadian-owned company, said the switch to natural gas "will lower the emission intensity profile of the facility

by approximately 50 percent."

"This project demonstrates the valuable role that legacy assets can play in supporting the State's clean energy laws and system reliability in a cost effective and timely fashion," added Kousinioris.

Under the agreement, the conversion will deliver 700 megawatts of power under a 16-year contract that runs through Dec. 31, 2044.

With California experiencing power disruptions as it switches to cleaner energy, some key Washington state officials have said they support adding natural gas to the facility.

In an interview conducted before the announcement, former Washington Gov. Christine Gregoire said she supported the company burning natural gas there as a backup while planned renewable energy projects around the state, like solar and wind power, get built.

During her tenure as governor, Gregoire, a Democrat, helped negotiate the agreement between TransAlta and the state that led to the winding down of the coal plant. She now serves on Puget Sound Energy's board.

"Natural gas today is under the gun, but it is the backup for us … to avoid the brownouts, blackouts," Gregoire said. "We do want to move to a clean energy future, but we have to do it in a way that we don't deprive people and businesses and communities of the energy they so desperately need."

She isn't alone with that perspective. State House Majority Leader Joe Fitzgibbon — a key architect of Democrats' clean-energy blueprint under Gregoire's successor, former Gov. Jay Inslee — said he supports TransAlta putting a natural-gas facility there for the short-term.

Gov. Bob Ferguson's office did not respond to emails seeking comment.

State Senate Minority Leader John Braun, a Republican from Centralia, said generating power through natural gas would help avoid California-style energy disruptions seen in recent years.

"We have to make the transition without hurting anybody," Braun said.

'Risk of power shortfalls'

The Centralia site had once included a neighboring coal mine, the largest such mine in Washington. By 2009, when Gregoire signed an executive order on climate change that declared an intent to strike a deal with the company, that mine had already shut down.

"They were having to bring coal in, there were all kinds of pressures," Gregoire said. "Whether that was a safety issue, a health issue, whether that was a good economic future for the people of Lewis County."

Subsequent negotiations led to the 2011 agreement being passed by the Legislature. The agreement spelled out the coal plant's decommissioning by the end of 2025 and secured the company an expedited consideration for a gas-powered facility.

The deal also secured $55 million from TransAlta to be spent on several things, including energy efficiency and economic development projects for the Centralia-area community.

"You can shut it down, and walk away, but what you leave behind is untenable," Gregoire said. "So it was really about trying to find the right way in which to leave the opportunity to help those people who would be out of a job, to retrain. And a new vision for Lewis County."

A recent study commissioned by Puget Sound Energy, Seattle City Light, Avista, Tacoma Power and others contends that Washington is already on the cusp of an electricity crisis.

The shift toward wind and solar has prompted the region to retire fossil fuel power faster than it has been replaced, according to the report released in September.

"Adding weather-dependent resources without balancing them with reliable backup has left the grid more exposed to extreme conditions," it stated.

The region "is going to have to add natural gas peaking plants as a critical backstop for reliability when the sun isn't shining or the wind isn't blowing," Matt Steuerwalt, a senior vice president with Puget Sound Energy, said in a statement.

"A key finding is the region is at risk of power shortfalls, which could lead to rolling blackouts during extreme conditions, such as a winter cold snap during a very low [hydropower] year," Steuerwalt said, citing that study. "This is a problem now – not 2030 or 2045, though it will get worse as demand continues to grow and more legacy power plants shut down."

In an email, state Senate Majority Leader Jamie Pedersen, D-Seattle, said officials continue to work "on speeding the transition to clean energy by increasing solar and wind generation; making our grid more efficient; and exploring technological solutions such as demand management to reduce peak period electricity demand."

"I suspect that we will also be extremely cautious about approving major new drains on the grid, such as data centers, that do not bring along dedicated generation facilities," Pedersen added.

In an interview, Fitzgibbon, the state House majority leader, said he's not opposed to TransAlta's shift to natural gas. Fitzgibbon previously chaired the House's energy and environment committee and sponsored the low-carbon fuel bill that passed in 2021. That was a key part of Democrats' ambitious plans to reduce carbon emissions that passed under Gregoire's successor, former Gov. Jay Inslee.

The envisioned TransAlta natural-gas facility, Fitzgibbon said, wouldn't be expected to operate decades into the future like brand-new construction. The lawmaker added that he isn't aware of any law that the Legislature would need to change to allow the project.

"Having coal out of Washington power is a huge milestone," Fitzgibbon added.

Braun, the Republican state Senate minority leader, also called the TransAlta property the second-best place in the state for the next generation of nuclear energy, behind the Hanford nuclear site in central Washington.

Under federal oversight, nuclear projects take many years and potentially decades to come to fruition. Braun urged Washington to pursue that option in Centralia, as well: "I'd like to see us get into that sooner and not later."

Editor's note: *This story was updated to note that former Washington Gov. Christine Gregoire now serves on Puget Sound Energy's board.*

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-111:
2023 GHG Washington Reporting Data

Reporter	Year	Sector	Subsector	Primary NA	NAICS Def	Parent Cor	City	County	Jurisdiction	Reported E	Biogenic C	Carbon Dic	Methane (M	Nitrous Ox	HFCs (MTC	PFCs (MTC	Sulfur Hex	Fluorinate	Notes	Point Size	Location	Covered Er	CCA Statu	Georeferenced Location
Phillips 66 Company - Houston	2023	Supplier	Other Fuel	424710	Petroleum	Phillips 66	Houston	Harris		8,911,628	393,323	8,415,579	9,462	93,264	0	0	0	0				6,847,794	Covered Entity	
Marathon Petroleum Co LP	2023	Supplier	Other Fuel	324110	Petroleum	Marathon I	Findlay	Hancock		8,451,024	351,849	7,996,211	9,526	93,437	0	0	0	0				6,773,968	Covered Entity	
BP Products North America	2023	Supplier	Other Fuel	324110	Petroleum	BP Americ	Houston	Harris		6,177,491	480,479	5,641,802	6,339	48,871	0	0	0	0				2,803,472	Covered Entity	
Puget Sound Energy LDC Supplier - Bellevue	2023	Supplier	Natural Ga	221210	Natural Ga	Puget Hold	Bellevue	King		5,262,258	34,193	5,222,636	2,477	2,952	0	0	0	0				5,369,985	Covered Entity	
TransAlta Centralia Generation LLC - Centralia	2023	Power Plar	Coal Plant	221112	Fossil Fuel	Transalta (	Centralia	Lewis	Southwest	4,536,949	0	4,501,387	13,008	22,554	0	0	0	0		5	46.7559, -122.8578	Reporter	POINT (-122.8578 46.7559)	
Equilon Enterprises LLC dba Shell Oil Products US	2023	Supplier	Other Fuel	424710	Petroleum	TMR COMF	Houston	Harris		4,095,258	111,280	3,946,401	4,768	32,809	0	0	0	0				1,695,920	Covered Entity	
Par Petroleum, LLC -Houston	2023	Supplier	Other Fuel	324110	Petroleum	Par Pacific	Houston	Harris		4,065,846	140,240	3,881,582	4,268	39,756	0	0	0	0				3,006,591	Covered Entity	
HF Sinclair Refining and Marketing LLC - Dallas	2023	Supplier	Other Fuel	324110	Petroleum	HF Sinclair	Dallas	Dallas		3,467,175	128,378	3,302,142	3,116	33,539	0	0	0	0				3,124,379	Covered Entity	
Chevron U.S.A. Inc.	2023	Supplier	Other Fuel	424710	Petroleum	Chevron C	San Ramor	Contra Costa		2,781,982	283,963	2,455,473	3,591	38,955	0	0	0	0				2,343,971	Covered Entity	
bp Cherry Point Refinery - Blaine	2023	Petroleum	Petroleum	324110	Petroleum	BP Americ	Blaine	Whatcom	Northwest	2,188,015	0	2,052,443	7,314	4,828	0	0	0	0		5	48.8864, -1	2,188,007	Covered Er	POINT (-122.7353 48.8864)
HF Sinclair Puget Sound Refinery LLC - Anacortes	2023	Petroleum	Petroleum	324110	Petroleum	HollyFront	Anacortes	Skagit	Northwest	1,900,999	0	1,890,710	6,317	3,971	0	0	0	0		4	48.470931	1,900,827	Covered Er	POINT (-122.559161 48.470931)
Cascade Natural Gas Corporation - supplier	2023	Supplier	Natural Ga	221210	Natural Ga	MDU Reso	Kennewick	Benton		1,690,675	0	1,688,931	796	949	0	0	0	0				1,905,915	Covered Entity	
River Road Generating Plant - Vancouver	2023	Power Plar	Natural Ga	221112	Fossil Fuel	Clark Publi	Vancouver	Clark	Southwest	700,250	0	1,399,077	649	774	0	0	0	0		4	45.64958,	700,250	Covered Er	POINT (-122.724806 45.64958)
Grays Harbor Energy Center - Elma	2023	Power Plar	Natural Ga	221112	Fossil Fuel	Invenergy I	Elma	Grays Harl	EFSEC	1,397,813	0	1,396,393	648	772	0	0	0	0		4	46.9688, -1	1,397,813	Covered Er	POINT (-123.48 46.9688)
Marathon Anacortes Refinery - Anacortes	2023	Petroleum	Petroleum	324110	Petroleum	Marathon I	Anacortes	Skagit	Northwest	1,202,267	0	1,196,960	2,228	3,079	0	0	0	0		4	48.493816	1,202,228	Covered Er	POINT (-122.564845 48.493816)
Avista Corporation - supplier	2023	Supplier	Natural Ga	221210	Natural Ga	Avista Cor	Spokane	Spokane		1,072,737	35	1,071,595	505	602	0	0	0	0				1,118,894	Covered Entity	
Chehalis Generation Facility - Chehalis	2023	Power Plar	Natural Ga	221112	Fossil Fuel	Berkshire I	Chehalis	Lewis	EFSEC	914,725	0	913,796	424	505	0	0	0	0		3	46.6226, -1	914,725	Covered Er	POINT (-122.9145 46.6226)
Phillips 66 Ferndale Refinery - Ferndale	2023	Petroleum	Petroleum	324110	Petroleum	Phillips 66	Ferndale	Whatcom	Northwest	902,436	0	898,414	1,807	2,216	0	0	0	0		3	48.830142	902,283	Covered Er	POINT (-122.692114 48.830142)
Puget Sound Energy - Goldendale Generating Station - Goldendale	2023	Power Plar	Natural Ga	221112	Fossil Fuel	Puget Hold	Goldendal	Klickitat	Ecology: C	826,172	0	825,333	383	456	0	0	0	0		3	45.8114, -1	826,172	Covered Er	POINT (-120.833 45.8114)
Puget Sound Energy - Mint Farm Generating Station - Longview	2023	Power Plar	Natural Ga	221112	Fossil Fuel	Puget Hold	Longview	Cowlitz	Southwest	798,751	0	797,939	370	441	0	0	0	0		3	46.140095	798,751	Covered Er	POINT (-122.985138 46.140095)
Puget Sound Energy - Ferndale Generating Station - Ferndale	2023	Power Plar	Natural Ga	221112	Fossil Fuel	Puget Hold	Ferndale	Whatcom	Northwest	715,257	0	714,523	333	401	0	0	0	0		3	48.828707	715,246	Covered Er	POINT (-122.685533 48.828707)
Frederickson Power LP - Tacoma	2023	Power Plar	Natural Ga	221112	Fossil Fuel	Puget Sour	Tacoma	Pierce	Puget Sour	708,701	0	707,981	328	391	0	0	0	0		3	47.086342	708,701	Covered Er	POINT (-122.365686 47.086342)
Puget Sound Energy - Fredonia Generating Station - Mount Vernon	2023	Power Plar	Natural Ga	221112	Fossil Fuel	Puget Hold	Mount Ver	Skagit	Northwest	641,257	0	640,595	301	361	0	0	0	0		3	48.4553, -1	641,250	Covered Er	POINT (-122.435 48.4553)
Hartland Fuel Products, LLC dba HTP Energy	2023	Supplier	Other Fuel	424720	Petroleum	PetroEnerg	Onalaska	La Crosse		606,230	6	604,482	500	1,242	0	0	0	0				22,987	Covered Entity	
NW Natural - supplier	2023	Supplier	Natural Ga	221210	Natural Ga	NW Nature	Portland	Multnomah		511,145	0	510,623	238	284	0	0	0	0				547,472	Covered Entity	
ExxonMobil Oil Corporation	2023	Supplier	Other Fuel	424710	Petroleum	ExxonMobi	Houston	Harris		489,317	24,539	457,759	583	6,436	0	0	0	0				464,778	Covered Entity	
CHS Inc.	2023	Supplier	Other Fuel	424720	Petroleum	CHS Inc.	Inver Grov	Dakota		451,648	10,578	437,553	388	3,130	0	0	0	0				366,752	Covered Entity	
Puget Sound Energy - Encogen Generating Station - Bellingham	2023	Power Plar	Natural Ga	221112	Fossil Fuel	Puget Hold	Bellingham	Whatcom	Northwest	427,033	0	426,599	198	236	0	0	0	0		3	48.746, -12	427,033	Covered Er	POINT (-122.486 48.746)
Puget Sound Energy - Sumas Generating Station - Sumas	2023	Power Plar	Natural Ga	221112	Fossil Fuel	Puget Hold	Sumas	Whatcom	Northwest	389,614	0	389,219	181	215	0	0	0	0		3	48.9905, -1	389,614	Covered Er	POINT (-122.2733 48.9905)
General Petroleum LLC - Seattle	2023	Supplier	Other Fuel	424720	Petroleum	Maxum En	Seattle	King		374,337	0	374,000	55	282	0	0	0	0				138,633	Covered Entity	
Nippon Dynawave - Longview	2023	Pulp and P	Kraft Mills	322121	Paper (exc	Nippon Pa	Longview	Cowlitz	Ecology: In	1,574,261	1,197,530	369,145	1,623	5,964	0	0	0	0	Formerly ir	4	46.130495	376,528	Covered Er	POINT (-122.983637 46.130495)
Ash Grove Cement Company - Seattle	2023	Minerals	Cement Pr	327310	Cement M	Ash Grove	Seattle	King	Puget Sour	367,651	0	366,730	325	596	0	0	0	0		3	47.56799,	367,651	Covered Er	POINT (-122.34255 47.56799)
SEI Fuel Services, Inc.	2023	Supplier	Other Fuel	424710	Petroleum	7-Eleven Ir	Irving	Dallas		364,510	22,558	335,742	503	5,706	0	0	0	0				341,952	Covered Entity	
Puget Sound Energy - Whitehorn Generating Station - Blaine	2023	Power Plar	Natural Ga	221112	Fossil Fuel	Puget Hold	Blaine	Whatcom	Northwest	308,591	0	308,273	145	173	0	0	0	0		3	48.885475	308,478	Covered Er	POINT (-122.724299 48.885475)
Coleman Oil Company, LLC	2023	Supplier	Other Fuel	424720	Petroleum	Coleman (	Lewiston	Nez Perce		336,928	27,277	307,699	166	1,786	0	0	0	0				189,329	Covered Entity	
Wilson Oil Inc	2023	Supplier	Other Fuel	424720	Petroleum	Wilson Oil	Longview	Cowlitz		294,993	13,279	278,159	296	3,260	0	0	0	0				277,882	Covered Entity	
Seaport Sound Terminal LLC - Tacoma	2023	Supplier	Other Fuel	493190	Other Ware	ArcLight Er	Tacoma	Pierce		389,240	113,091	270,199	683	5,268	0	0	0	0				137,806	Covered Entity	
WestRock LLC - Longview	2023	Pulp and P	Kraft Mills	322130	Paperboar	Westrock (	Longview	Cowlitz	Ecology: In	1,311,764	1,129,402	176,257	1,162	4,943	0	0	0	0		4	46.10361,	182,345	Covered Er	POINT (-122.92167 46.10361)
U.S. Oil & Refining Co. - Tacoma	2023	Petroleum	Petroleum	324110	Petroleum	Par Pacific	Tacoma	Pierce	Puget Sour	148,012	0	146,643	873	496	0	0	0	0		3	47.256813	148,009	Covered Er	POINT (-122.394952 47.256813)
Idemitsu Apollo Corporation - Sacramento	2023	Supplier	Other Fuel	424710	Petroleum	Idemitsu A	Sacramen	Sacramento		141,420	4,534	136,569	32	284	0	0	0	0				93,602	Covered Entity	
Petrogas, Inc. - Calgary	2023	Supplier	Other Fuel	424720	Petroleum	Altagas Ltc	Calgary	MD of Foothills No. 31		132,333	0	131,803	157	374	0	0	0	0				128,324	Covered Entity	
Gas Transmission Northwest Compressor Station 7 -Prescott	2023	Natural Ga	Natural Ga	486210	Pipeline Tr	TransCana	Starbuck	Columbia	Ecology: Ea	133,778	0	131,653	2,051	74	0	0	0	0		3	46.53558,	133,778	Covered Er	POINT (-118.293441 46.53558)
Gas Transmission Northwest Compressor Station 8, LLC -Wallula	2023	Natural Ga	Natural Ga	486210	Pipeline Tr	TransCana	Wallula	Walla Wall	Ecology: Ea	133,440	0	131,297	2,069	74	0	0	0	0		3	46.053153	133,440	Covered Er	POINT (-118.843934 46.053153)
Kaiser Aluminum Washington, LLC (Trentwood Works) - Spokane Valley	2023	Metals	Other Meta	331315	Aluminum	Kaiser Alur	Spokane V	Spokane	Spokane R	124,834	0	124,706	59	70	0	0	0	0		3	47.687074	124,833	Covered Er	POINT (-117.212673 47.687074)
Midstream Energy Partners (USA), LLC -Tupman	2023	Supplier	Other Fuel	424720	Petroleum	South 49 H	Tupman	Kern		124,898	0	124,397	148	353	0	0	0	0				91,117	Covered Entity	
Puget Sound Energy - Frederickson Generating Station - Tacoma	2023	Power Plar	Natural Ga	221112	Fossil Fuel	Puget Hold	Tacoma	Pierce	Puget Sour	118,782	98	118,560	56	68	0	0	0	0		3	47.079716	117,908	Covered Er	POINT (-122.364711 47.079716)
WestRock CP, LLC - Tacoma	2023	Pulp and P	Kraft Mills	322130	Paperboar	Westrock (	Tacoma	Pierce	Ecology: In	681,798	563,024	115,229	654	2,891	0	0	0	0		3	47.260953	118,774	Covered Er	POINT (-122.421765 47.260953)
Gas Transmission Northwest Compressor Station 6, LLC - Rosalia	2023	Natural Ga	Natural Ga	486210	Pipeline Tr	TransCana	Rosalia	Whitman	Spokane R	113,467	0	112,145	1,259	63	0	0	0	0		3	47.277256	113,467	Covered Er	POINT (-117.406737 47.277256)
Cardinal FG Company - Winlock	2023	Minerals	Glass Proc	327211	Flat Glass	Cardinal G	Winlock	Lewis	Southwest	107,118	0	107,043	34	41	0	0	0	0		3	46.544937	107,118	Covered Er	POINT (-122.926313 46.544937)
Northwest Pipeline C/S - Sumas	2023	Natural Ga	Natural Ga	486210	Pipeline Tr	The Williar	Sumas	Whatcom	Northwest	105,282	0	102,379	2,846	58	0	0	0	0		3	49.001, -12	105,282	Covered Er	POINT (-122.2214 49.001)
Spokane Waste to Energy Facility - Spokane	2023	Power Plar	Other Pow	562213	Solid Wast	City of Spo	Spokane	Spokane	Spokane R	232,129	131,530	95,490	1,992	3,116	0	0	0	0		3	47.626529,	-117.5042	Reporter	POINT (-117.504278 47.626529)
Packaging Corporation of America - Wallula	2023	Pulp and P	Kraft Mills	322121	Paper (exc	Packaging	Wallula	Walla Wall	Ecology: In	318,762	219,269	83,592	15,297	604	0	0	0	0		3	46.10396,	97,977	Covered Er	POINT (-118.9184 46.10396)
Nucor Steel Seattle, Inc, - Seattle	2023	Metals	Iron and St	331110	Iron and St	Nucor Cor	Seattle	King	Puget Sour	82,396	0	82,355	19	22	0	0	0	0		2	47.569331	82,396	Covered Er	POINT (-122.367332 47.569331)
KIROS Energy Marketing ULC - Calgary	2023	Supplier	Other Fuel	424720	Petroleum	Kiros Ener	Calgary	MD of Foothills No. 31		82,643	0	82,312	98	234	0	0	0	0				37,318	Covered Entity	
University of Washington Seattle Campus - Seattle	2023	Governme	Education	611310	Colleges, U	State of W	Seattle	King	Puget Sour	80,936	0	80,851	38	46	0	0	0	0		2	47.653614	80,376	Covered Er	POINT (-122.303608 47.653614)
Colvin Oil I LLC - Josephine	2023	Supplier	Other Fuel	457110	Gasoline S	Colvin Oil I	Grants Pas	Josephine		83,663	5,360	76,971	108	1,224	0	0	0	0				78,303	Covered Entity	
Northwest Pipeline C/S - Mount Vernon	2023	Natural Ga	Natural Ga	486210	Pipeline Tr	The Williar	Mount Ver	Skagit	Northwest	74,378	0	72,462	1,875	41	0	0	0	0		2	48.421967	74,378	Covered Er	POINT (-122.21547 48.421967)
Air Liquide Hydrogen Plant - Anacortes	2023	Petroleum	Other Petr	325120	Industrial (	Air Liquide	Anacortes	Skagit	Northwest	72,277	0	72,277	0	0	0	0	0	0		2	48.465617	72,277	Covered Er	POINT (-122.556032 48.465617)
CenTrio Energy Seattle LLC - Seattle	2023	Power Plar	Other Pow	221330	Steam and	Seattle Ste	Seattle	King	Puget Sour	68,651	0	68,576	33	41	0	0	0	0		2	47.6068, -1	67,317	Covered Er	POINT (-122.340179 47.6068)
Northwest Pipeline C/S - Snohomish	2023	Natural Ga	Natural Ga	486210	Pipeline Tr	The Williar	Snohomish	Snohomish	Puget Sour	69,638	0	67,266	2,335	38	0	0	0	0		2	47.78825,	69,638	Covered Er	POINT (-122.05859 47.78825)
Boeing Commercial Airplanes - Everett	2023	Manufactu	Transporta	336411	Aircraft Ma	The Boeing	Everett	Snohomish	Puget Sour	66,124	0	66,056	31	38	0	0	0	0		2	47.918622	65,836	Covered Er	POINT (-122.276987 47.918622)
World Fuel Services, Inc.	2023	Supplier	Other Fuel	424720	Petroleum	World Fuel	Miami	Miami-Dade		74,778	8,829	65,254	69	626	0	0	0	0				65,949	Covered Entity	
LANXESS Corporation - Kalama	2023	Chemicals	Other Chei	325199	All Other B	Emerald Pe	Kalama	Cowlitz	Southwest	60,120	0	60,058	28	34	0	0	0	0		2	46.02191,	60,120	Covered Er	POINT (-122.85698 46.02191)
Washington State University - Pullman	2023	Governme	Education	611310	Colleges, U	State of W	Pullman	Whitman	Ecology: Ea	59,448	0	59,360	34	54	0	0	0	0		2	46.728702	48,424	Covered Er	POINT (-117.151481 46.728702)
Space Age Fuel, Inc - Clackamas	2023	Supplier	Other Fuel	424710	Petroleum	SPACE AGI	Clackama	Clackamas		116,494	57,443	58,268	67	716	0	0	0	0				59,051	Covered Entity	
Port Townsend Paper Corporation - Port Townsend	2023	Pulp and P	Kraft Mills	322121	Paper (exc	Port Towns	Port Towns	Jefferson	Ecology: In	553,804	491,477	57,063	2,542	2,721	0	0	0	0		3	48.093793	62,287	Covered Er	POINT (-122.796806 48.093793)
US Army Joint Base Lewis-McChord - Pierce Co.	2023	Governme	National S	928110	National S	US Govern	Joint Base	Pierce	Puget Sour	71,411	0	56,808	14,570	33	0	0	0	0		2	47.1142, -122.5365		Reporter	POINT (-122.5365 47.1142)
Lamb Weston - Richland	2023	Food Prod	Potato Pro	311411	Frozen Fru	Lamb Wes	Richland	Benton	Benton Cle	84,081	9,355	56,530	18,131	66	0	0	0	0		2	46.309314	74,726	Covered Er	POINT (-119.297267 46.309314)
CertainTeed Gypsum - Seattle	2023	Manufactu	Building Pr	327420	Gypsum Pr	Saint-Gobi	Seattle	King	Puget Sour	55,645	0	55,587	26	31	0	0	0	0		2	47.548056	55,645	Covered Er	POINT (-122.336944 47.548056)
Matheson - Anacortes	2023	Petroleum	Other Petr	325120	Industrial (	Linde Gas	Anacortes	Skagit	Northwest	53,407	0	53,407	0	0	0	0	0	0		2	48.467646	53,407	Covered Er	POINT (-122.554343 48.467646)
J.R. Simplot Company - Othello	2023	Food Prod	Potato Pro	311411	Frozen Fru	J.R. Simplo	Othello	Adams	Ecology: Ea	107,817	0	53,175	54,613	30	0	0	0	0		3	46.837778	107,817	Covered Er	POINT (-119.176389 46.837778)
McCain Foods - Othello	2023	Food Prod	Potato Pro	311411	Frozen Fru	McCain US	Othello	Adams	Ecology: Ea	68,869	9,488	50,896	8,423	63	0	0	0	0		2	46.840102	59,381	Covered Er	POINT (-119.172705 46.840102)
Northwest Pipeline C/S - Sumner	2023	Natural Ga	Natural Ga	486210	Pipeline Tr	The Williar	Sumner	Pierce	Puget Sour	51,136	0	50,579	529	28	0	0	0	0		2	47.228986	51,136	Covered Er	POINT (-122.209551 47.228986)
Solvay Chemicals, Inc. - Longview	2023	Chemicals	Other Chei	325180	Other Basi	Solvay Che	Longview	Cowlitz	Southwest	50,068	0	50,068	0	0	0	0	0	0		2	46.137218	50,068	Covered Er	POINT (-122.982847 46.137218)
Georgia-Pacific Gypsum LLC - Tacoma	2023	Manufactu	Building Pr	327420	Gypsum Pr	Koch Indus	Tacoma	Pierce	Puget Sour	49,843	0	49,792	23	28	0	0	0	0		2	47.269558	49,843	Covered Er	POINT (-122.394869 47.269558)
Georgia-Pacific Consumer Operations LLC - Camas	2023	Pulp and P	Kraft Mills	322120	Paper Mills	Koch Indus	Camas	Clark	Ecology: In	53,794	0	48,436	5,331	27	0	0	0	0		2	45.584271	53,794	Covered Er	POINT (-122.40843 45.584271)
Xpress Natural Gas: SATSOP	2023	Supplier	Natural Ga	221210	Natural Ga	Xpress Nat	Elma	Grays Harbor		45,474	0	45,427	22	26	0	0	0	0					Reporter	
Ardagh Glass Inc. - Seattle	2023	Minerals	Glass Proc	327213	Glass Con	Ardagh Ho	Seattle	King	Puget Sour	44,364	0	44,329	16	19	0	0	0	0	Facility cur	2	47.55242,	44,364	Covered Er	POINT (-122.33739 47.55242)

CECO, Inc. - Portland	2023	Supplier	Other Fuel	424710	Petroleum	CECO, Inc	Portland	Multnomah		46,952	3,537	43,065	35	316	0	0	0	0				42,706	Covered Entity								
Goodrich Corporation - Spokane	2023	Manufactu	Transporta	336413	Other Aircr	Raytheon	Spokane	Spokane	Spokane R	42,340	0	42,293	21	26	0	0	0	0	2	47.583604		41,339	Covered Ei	POINT (-117.568511	47.583604)						
Christensen, Inc. - Richland	2023	Supplier	Other Fuel	424720	Petroleum	Christense	Richland	Benton		43,388	1,221	41,826	42	299	0	0	0	0				42,167	Covered Entity								
Naval Base Kitsap - Bremerton	2023	Governme	National S	928110	National S	US Govern	Bremerton	Kitsap	Puget Sour	41,809	0	41,765	20	24	0	0	0	0	2	47.557047,	-122.6459	Reporter	POINT (-122.645933	47.557047)						
Kiva United Energy - San Joaquin	2023	Supplier	Other Fuel	424720	Petroleum	Kiva Unite	Manteca	San Joaquin		38,040	0	37,888	45	108	0	0	0	0				26,683	Covered Entity								
Darigold - Sunnyside	2023	Food Prodi	Dairy Prod	311513	Cheese Ma	Darigold In	Sunnyside	Yakima	Yakima Re	36,711	0	36,673	18	21	0	0	0	0	2	46.30058,		36,711	Covered Ei	POINT (-120.015675	46.30058)						
North Pacific Paper Company, LLC - Longview	2023	Pulp and P	Other Pulp	322122	Newsprint	NP Paper I	Longview	Cowlitz	Southwest	36,395	0	36,357	17	21	0	0	0	0	Formerly p		2	46.125662	36,395	Covered Ei	POINT (-122.976788	46.125662)					
Lamb Weston - Pasco	2023	Food Prodi	Potato Pro	311411	Frozen Fru	Lamb Wes	Pasco	Franklin	Ecology: Ea	35,750	0	35,713	17	20	0	0	0	0			2	46.288137	35,750	Covered Ei	POINT (-119.115336	46.288137)					
The Boeing Company - Auburn Site - Auburn	2023	Manufactu	Transporta	336413	Other Aircr	The Boeing	Auburn	King	Puget Sour	33,303	0	33,269	16	19	0	0	0	0			2	47.285551	33,130	Covered Ei	POINT (-122.242298	47.285551)					
Washington Potato Company - Warden	2023	Food Prodi	Potato Pro	311991	Perishable	Washingto	Warden	Grant	Ecology: Ea	31,872	0	31,839	15	18	0	0	0	0			2	46.970469	31,872	Covered Ei	POINT (-119.063631	46.970469)					
NGL Energy Partners LP	2023	Supplier	Other Fuel	424720	Petroleum	NGL Energ	Tulsa	Tulsa		31,881	0	31,753	38	90	0	0	0	0				31,881	Covered Entity								
Boulder Park Generating Station - Spokane Valley	2023	Power Plar	Other Pow	221112	Fossil Fuel	Avista Cor	Spokane V	Spokane	Spokane R	31,456	0	31,424	15	18	0	0	0	0			2	47.696999	31,456	Covered Ei	POINT (-117.147223	47.696999)					
The Andersons Inc. - Overland Park	2023	Supplier	Other Fuel	115114	Postharves	The Anders	Overland F	Johnson		31,361	0	31,235	37	89	0	0	0	0				31,361	Covered Entity								
Lamb Weston - Quincy	2023	Food Prodi	Potato Pro	311411	Frozen Fru	Lamb Wes	Quincy	Grant	Ecology: Ea	29,971	0	29,941	14	17	0	0	0	0	2	47.234413		29,971	Covered Ei	POINT (-119.869914	47.234413)						
City of Ellensburg LDC - supplier	2023	Supplier	Natural Ga	221210	Natural Ga	City of Elle	Ellensburg	Kittitas		28,110	0	28,081	13	16	0	0	0	0				41,017	Covered Entity								
Fred Meyer Stores Inc	2023	Supplier	Other Fuel	457120	Other Gas	KROGER C	Hutchinso	Reno		30,580	2,020	28,021	44	495	0	0	0	0				28,560	Covered Entity								
Pilot Travel Centers LLC - Knoxville	2023	Supplier	Other Fuel	457120	Other Gas	Pilot Trave	Knoxville	Knox		27,266	276	26,964	4	23	0	0	0	0				26,991	Covered Entity								
Lamb Weston - Connell	2023	Food Prodi	Potato Pro	311411	Frozen Fru	Lamb Wes	Connell	Franklin	Ecology: Ea	26,956	0	26,929	13	15	0	0	0	0	2	46.651389		26,956	Covered Ei	POINT (-118.871944	46.651389)						
Targa Liquids Marketing and Trade LLC - Houston	2023	Supplier	Other Fuel	424720	Petroleum	Targa Resc	Houston	Harris		26,727	0	26,620	32	76	0	0	0	0				26,727	Covered Entity								
Tyson Fresh Meats, Inc. - Wallula	2023	Food Prodi	Meat Prodi	311611	Animal (ex	Tyson Foo	Wallula	Walla Wall	Ecology: Ea	100,445	0	26,384	74,044	17	0	0	0	0	3	46.137521		99,431	Covered Ei	POINT (-118.913051	46.137521)						
City of Enumclaw Gas Utility - supplier	2023	Supplier	Natural Ga	221210	Natural Ga	City of Enu	Enumclaw	King		26,084	0	26,057	12	15	0	0	0	0				26,084	Covered Entity								
VGP Holdings LLC - Lexington	2023	Supplier	Other Fuel	324121	Asphalt Pa	VGP Holdi	Lexington	Fayette		25,887	0	25,799	26	62	0	0	0	0				25,887	Covered Entity								
Basic American Foods - Moses Lake	2023	Food Prodi	Potato Pro	311423	Dried and I	Basic Ame	Moses Lak	Grant	Ecology: Ea	24,544	0	24,519	12	14	0	0	0	0	1	47.075183		24,544	Covered Ei	POINT (-119.220408	47.075183)						
WSCO Petroleum Corporation	2023	Supplier	Other Fuel	424710	Petroleum	WSCO Pet	Portland	Multnomah		26,279	1,731	24,068	39	441	0	0	0	0					Reporter								
Gee Cee's Inc.- Toledo	2023	Supplier	Other Fuel	457110	Gasoline S	Gee Cee s	Toledo	Lewis		23,873	12	23,839	3	19	0	0	0	0					Reporter								
The Boeing Company: Boeing Plant 2 - Seattle	2023	Manufactu	Transporta	336411	Aircraft Ma	The Boeing	Seattle	King	Puget Sour	23,047	0	23,022	11	14	0	0	0	0	1	47.532524,	-122.3116	Reporter	POINT (-122.311623	47.532524)						
U.S. Department of Energy Hanford Site - Richland	2023	Governme	Other Gove	924110	Administra	US Govern	Richland	Benton	Ecology: N	30,899	0	22,384	8,464	51	0	0	0	0	2	46.55069,	-119.48900	Reporter	POINT (-119.489007	46.55069)						
MIECO Inc.	2023	Supplier	Other Fuel	324110	Petroleum	MARUBEN	Long Beac	Los Angeles		24,260	1,595	22,223	36	406	0	0	0	0					Reporter								
Owens-Brockway Glass Container Inc Plant #2 - Kalama	2023	Minerals	Glass Proc	327213	Glass Con	O-I Glass I	Kalama	Cowlitz	Southwest	21,704	0	21,688	8	9	0	0	0	0	1	46.031656		21,704	Covered Ei	POINT (-122.866241	46.031656)						
Northwest Pipeline C/S - Chehalis	2023	Natural Ga	Natural Ga	486210	Pipeline Tr	The Williar	Chehalis	Lewis	Southwest	22,485	0	21,535	938	12	0	0	0	0	1	46.533325		22,485	Covered Ei	POINT (-122.87373	46.533325)						
Johnston's Grain Connected Ltd.	2023									21,383	0	21,297	25	61	0	0	0	0					Reporter								
Jackson Food Stores - Meridian	2023	Supplier	Other Fuel	457110	Gasoline S	Jacksons F	Meridian	Ada		23,136	1,501	21,254	31	349	0	0	0	0				21,634	Covered Entity								
NGL Supply Co. Ltd. - Sarnia	2023	Supplier	Other Fuel	424720	Petroleum	NGL Suppl	Sarnia	Lambton		21,259	0	21,173	25	60	0	0	0	0				15,385	Covered Entity								
PetroCard Inc.	2023	Supplier	Other Fuel	424720	Petroleum	Bristol Bay	Kent	King		22,719	2,057	20,618	5	39	0	0	0	0					Reporter								
REG Grays Harbor LLC - Hoquiam	2023	Petroleum	Other Petr	325199	All Other B	Chevron C	Hoquiam	Grays Harl	Olympic Re	20,092	0	20,072	10	11	0	0	0	0	1	46.968196,	-123.8536	Reporter	POINT (-123.853622	46.968196)						
Darigold - Lynden	2023	Food Prodi	Dairy Prod	311514	Dry, Cond	Darigold In	Lynden	Whatcom	Northwest	19,713	0	19,693	9	11	0	0	0	0	1	48.947567,	-122.4519	Reporter	POINT (-122.451915	48.947567)						
Naval Base Kitsap Bangor - Silverdale	2023	Governme	National S	928110	National S	US Govern	Silverdale	Kitsap	Puget Sour	19,431	0	19,409	10	13	0	0	0	0	1	47.699284,	-122.6969	Reporter	POINT (-122.696926	47.699284)						
The Boeing Company - Renton	2023	Manufactu	Transporta	336411	Aircraft Ma	The Boeing	Renton	King	Puget Sour	19,424	0	19,404	9	11	0	0	0	0	1	47.498257,	-122.2113	Reporter	POINT (-122.211346	47.498257)						
Musket Corporation - Houston	2023	Supplier	Other Fuel	457120	Other Gas	Love s Tra	Houston	Harris		77,075	58,224	18,732	16	103	0	0	0	0					Reporter								
Northwest Pipeline C/S - Goldendale	2023	Natural Ga	Natural Ga	486210	Pipeline Tr	The Williar	Goldendal	Klickitat	Ecology: C	20,993	0	18,668	2,315	10	0	0	0	0	1	45.771216		20,993	Covered Ei	POINT (-120.799267	45.771216)						
Steelscape - Kalama	2023	Metals	Other Meta	331221	Rolled Ste	NS BlueSc	Kalama	Cowlitz	Southwest	18,633	0	18,614	9	10	0	0	0	0	1	46.04326,		18,633	Covered Ei	POINT (-122.871703	46.04326)						
J.R. Simplot Company - Moses Lake	2023	Food Prodi	Potato Pro	311411	Frozen Fru	J.R. Simplc	Moses Lak	Grant	Ecology: Ea	30,430	4,159	18,246	8,000	25	0	0	0	0	2	47.131732		26,271	Covered Ei	POINT (-119.18926	47.131732)						
Tree Top - Prosser	2023	Food Prodi	Fruit Produ	311411	Frozen Fru	Tree Top In	Prosser	Benton	Benton Cle	18,249	0	18,231	9	10	0	0	0	0	1	46.21842,	-119.73397	Reporter	POINT (-119.73397	46.21842)						
Costco Wholesale Corporation - Issaquah	2023	Supplier	Other Fuel	455219	All Other G	Costco Wh	Issaquah	King		19,166	1,151	17,665	28	322	0	0	0	0					Reporter								
Factor Gas Liquids Inc. - Ontario	2023	Supplier	Other Fuel	424720	Petroleum	Factor Gas	Sarnia	Lambton		17,709	0	17,638	21	50	0	0	0	0					Reporter								
Boise Cascade Wood Products, LLC. Kettle Falls Plywood - Kettle Falls	2023	Wood Proc	Other Woo	321219	Reconstitu	Boise Cas	Kettle Falls	Stevens	Ecology: Ea	74,476	56,228	17,480	116	653	0	0	0	0	2	48.613175,	-118.1161	Reporter	POINT (-118.116106	48.613175)						
Ed Staub & Sons Petroleum, Inc - Klamath	2023	Supplier	Other Fuel	424720	Petroleum	Ed Staub &	Klamath F	Klamath		18,751	1,171	17,331	21	228	0	0	0	0				14,586	Covered Entity								
Seattle-Tacoma International Airport - Seattle	2023	Governme	Other Gove	488119	Other Airpo	Port of Sea	Seattle	King	Puget Sour	16,544	0	16,527	8	10	0	0	0	0	1	47.443643,	-122.3024	Reporter	POINT (-122.302452	47.443643)						
Tidewater Barge Lines - Vancouver	2023	Supplier	Other Fuel	424710	Petroleum	Tidewater	Vancouver	Clark		16,438	0	16,424	2	12	0	0	0	0					Reporter								
NorthStar Energy, LLC - Seattle	2023	Supplier	Other Fuel	424710	Petroleum	Saltchuk H	Seattle	King		16,865	331	16,409	17	108	0	0	0	0				13,660	Covered Entity								
The Boeing Company: DC/MFC - Tukwila	2023	Manufactu	Transporta	336411	Aircraft Ma	The Boeing	Tukwila	King	Puget Sour	16,355	0	16,338	8	9	0	0	0	0	1	47.516246,	-122.2986	Reporter	POINT (-122.298613	47.516246)						
Inland Empire Paper Company - Spokane	2023	Pulp and P	Other Pulp	322122	Newsprint	Cowles Pu	Spokane	Spokane	Spokane R	32,249	15,753	16,269	38	190	0	0	0	0	2	47.688295,	-117.2793	Reporter	POINT (-117.279323	47.688295)						
TYREE OIL INC - Eugene	2023	Supplier	Other Fuel	424720	Petroleum	TYREE OIL	Eugene	Lane		16,488	194	16,238	10	45	0	0	0	0					Reporter								
Kettle Falls Generating Station - Kettle Falls	2023	Power Plar	Other Pow	221117	Biomass E	Avista Cor	Kettle Falls	Stevens	Ecology: Ea	464,244	442,112	16,211	856	5,065	0	0	0	0	3	48.620335,	-118.1108	Reporter	POINT (-118.110841	48.620335)						
The Boeing Company - Fabrication (Frederickson Site) - Puyallup	2023	Manufactu	Transporta	336411	Aircraft Ma	The Boeing	Puyallup	Pierce	Puget Sour	16,168	0	16,152	8	9	0	0	0	0	1	47.088831,	-122.3486	Reporter	POINT (-122.34862	47.088831)						
EcoLube Recovery, LLC - Portland	2023	Supplier	Other Fuel	324191	Petroleum	EcoLube R	Portland	Multnomah		16,085	0	16,029	16	39	0	0	0	0					Reporter								
Tree Top - Selah Campus	2023	Food Prodi	Fruit Produ	311423	Dried and I	Tree Top In	Selah	Yakima	Yakima Re	15,742	0	15,726	8	9	0	0	0	0	1	46.64992,	-120.52755	Reporter	POINT (-120.52755	46.64992)						
Hattenhauer Distributing Co - The Dalles	2023	Supplier	Other Fuel	457110	Gasoline S	Hattenhau	The Dalles	Wasco		16,828	1,018	15,604	17	189	0	0	0	0					Reporter								
Imerys Minerals Quincy Plant - Quincy	2023	Minerals	Other Mine	212399	All Other N	Imerys Filt	Quincy	Grant	Ecology: Ea	15,599	0	15,583	7	9	0	0	0	0	1	47.239948,	-119.8388	Reporter	POINT (-119.838831	47.239948)						
Tacoma LNG - Facility	2023	Natural Ga	Natural Ga	221210	Natural Ga	Puget Sour	Tacoma	Pierce	Puget Sour	15,537	0	15,516	21	0	0	0	0	0	1	47.274788,	-122.4003	Reporter	POINT (-122.400326	47.274788)						
James Hardie Building Products - Tacoma	2023	Manufactu	Building Pr	327390	Other Con	James Har	Tacoma	Pierce	Puget Sour	14,984	0	14,969	7	8	0	0	0	0	1	47.092145,	-122.3646	Reporter	POINT (-122.364656	47.092145)						
WaferTech LLC - Camas	2023	Manufactu	Electronics	334413	Semicondi	WaferTech	Camas	Clark	Southwest	73,391	0	14,776	7	5,368	7,671	19,186	9,879	16,503	2	45.619569		73,259	Covered Ei	POINT (-122.454955	45.619569)						
Flashpoint Energy Partners, LLC - Tulsa	2023	Supplier	Other Fuel	Supplier		Flashpoint	Tulsa	Tulsa		14,347	0	14,290	17	41	0	0	0	0					Reporter								
Lamb Weston - Warden	2023	Food Prodi	Potato Pro	311411	Frozen Fru	Lamb Wes	Warden	Grant	Ecology: Ea	14,112	0	14,097	7	8	0	0	0	0	1	46.971504,	-119.0554	Reporter	POINT (-119.055427	46.971504)						
Eastern Washington University	2023	Governme	Education	611310	Colleges, U	State of W	Cheney	Spokane	Spokane R	14,065	0	14,051	7	8	0	0	0	0	1	47.490091,	-117.5797	Reporter	POINT (-117.579702	47.490091)						
Parkland Corporation - Calgary	2023	Supplier	Other Fuel	Supplier		Parkland C	Calgary	MD of Foothills No. 31		13,865	0	13,854	2	10	0	0	0	0				13,865	Covered Entity								
Ascensus Specialties LLC - Elma	2023	Chemicals	Other Che	325180	Other Basi	VSI Holdin	Elma	Grays Harl	Olympic Re	13,860	0	13,845	7	8	0	0	0	0	1	46.995459,	-123.3823	Reporter	POINT (-123.382316	46.995459)						
Star Tank Lines - Sonoma	2023	Supplier	Other Fuel	457210	Fuel Deale	Garbervill	Santa Ros	Sonoma		18,422	4,888	13,460	22	52	0	0	0	0					Reporter								
Fairchild AFB - Spokane Co.	2023	Governme	National S	928110	National S	US Govern	Fairchild A	Spokane	Spokane R	13,446	0	13,433	6	7	0	0	0	0	1	47.641332,	-117.6448	Reporter	POINT (-117.644832	47.641332)						
Frito Lay - Vancouver	2023	Food Prodi	Other Fooc	311919	Other Snac	PepsiCo In	Vancouver	Clark	Southwest	13,363	0	13,350	6	7	0	0	0	0	1	45.657037,	-122.692	Reporter	POINT (-122.692	45.657037)						
Darigold - Chehalis	2023	Food Prodi	Dairy Prod	311514	Dry, Cond	Darigold In	Chehalis	Lewis	Southwest	13,263	0	13,250	6	7	0	0	0	0	1	46.659952,	-122.9701	Reporter	POINT (-122.970162	46.659952)						
Greif, Tacoma Mill - Tacoma	2023	Pulp and P	Other Pulp	322130	Paperboar	Paperboar	Tacoma	Pierce	Puget Sour	13,060	0	13,047	6	7	0	0	0	0	1	47.239235,	-122.4219	Reporter	POINT (-122.421909	47.239235)						
Sun Pacific Energy, Inc - Kennewick	2023	Supplier	Other Fuel	Supplier		SUN PACIF	Kennewick	Benton		14,197	919	13,044	19	216	0	0	0	0					Reporter								
Puget Sound Energy - Jackson Prairie Gas Storage - Chehalis	2023	Natural Ga	Natural Ga	486210	Pipeline Tr	Puget Hold	Chehalis	Lewis	Southwest	14,652	0	12,889	1,756	7	0	0	0	0	1	46.53461,	-122.83856	Reporter	POINT (-122.838569	46.53461)						
Central Washington University - Ellensburg	2023	Governme	Education	611310	Colleges, U	State of W	Ellensburg	Kittitas	Ecology: C	12,790	0	12,777	6	7	0	0	0	0	1	47.003202,	-120.5445	Reporter	POINT (-120.544513	47.003202)						
Naval Air Station Whidbey Island - Oak Harbor	2023	Governme	National S	928110	National S	US Govern	Oak Harbo	Island	Northwest	12,779	0	12,766	6	8	0	0	0	0	1	48.345281,	-122.6697	Reporter	POINT (-122.669741	48.345281)						
Keyes Fibre Corporation - Wenatchee	2023	Pulp and P	Other Pulp	322299	All Other C	Tekni-Plex	Wenatchee	Chelan	Ecology: C	12,427	0	12,414	6	7	0	0	0	0	1	47.485987,	-120.3163	Reporter	POINT (-120.316363	47.485987)						
SGL Carbon, LLC - Moses Lake	2023	Manufactu	Transporta	335991	Carbon an	SGL Autom	Moses Lak	Grant	Ecology: Ea	12,414	0	12,401	6	7	0	0	0	0	1	47.208993,	-119.2854	Reporter	POINT (-119.285437	47.208993)						
Providence Sacred Heart Medical Center - Spokane	2023	Health Car	Hospitals	622110	General M	Providence	Spokane	Spokane	Spokane R	12,106	0	12,093	6	7	0	0	0	0	1	47.648848,	-117.4124	Reporter	POINT (-117.412461	47.648848)						

Starbucks Kent Flexible Plant - Kent	2023	Food Prodı	Other Fooc	311920	Coffee anc	Starbucks	Kent	King	Puget Sour	12,057	0	12,044	6	7	0	0	0	0		1	47.436276, -122.2376	Reporter	POINT (-122.237648 47.436276)
Michelsen Packaging - Yakima	2023	Pulp and P	Other Pulp	322299	All Other C	Michelson	Yakima	Yakima	Yakima Re	11,886	0	11,874	6	7	0	0	0	0		1	46.604058, -120.5130	Reporter	POINT (-120.513015 46.604058)
Great Western Malt - Vancouver	2023	Food Prodı	Other Fooc	311213	Malt Manu	Great Wes	Vancouver	Clark	Southwest	11,815	0	11,803	6	7	0	0	0	0		1	45.631069, -122.6900	Reporter	POINT (-122.690043 45.631069)
Pasco Processing LLC - Pasco	2023	Food Prodı	Other Fooc	311991	Perishable	Oregon Po	Pasco	Franklin	Ecology: Ea	11,545	0	11,533	6	7	0	0	0	0		1	46.28274, -119.09752	Reporter	POINT (-119.097528 46.28274)
EPIC Aviation LLC	2023	Supplier	Other Fuel	424710	Petroleum	Signature /	Salem	Marion		16,107	4,706	11,358	12	31	0	0	0	0				Reporter	
Western Washington University - Bellingham	2023	Governme	Education	611310	Colleges, l	Western W	Bellingham	Whatcom	Northwest	11,165	0	11,154	5	6	0	0	0	0		1	48.736499, -122.4847	Reporter	POINT (-122.484714 48.736499)
Sonoco Products - Sumner	2023	Pulp and P	Other Pulp	322130	Paperboar	Sonoco Pr	Sumner	Pierce	Puget Sour	10,985	0	10,974	5	6	0	0	0	0		1	47.210641, -122.2394	Reporter	POINT (-122.239474 47.210641)
Devin Oil Co Inc - Hermiston	2023	Supplier	Other Fuel	424710	Petroleum	Devin Oil C	Hermiston	Umatilla		12,199	1,202	10,826	14	157	0	0	0	0				Reporter	
SEH America, Inc - Vancouver	2023	Manufactu	Electronics	334413	Semicondı	SEH Ameri	Vancouver	Clark	Southwest	10,638	0	10,628	5	6	0	0	0	0		1	45.649912, -122.5536	Reporter	POINT (-122.553612 45.649912)
AmeriGas Propane - King of Prussia	2023	Supplier	Other Fuel	457210	Fuel Deale	UGI Corp	King of Pru	Montgomery		9,873	0	9,834	12	28	0	0	0	0			1,095	Covered Entity	
Tree Top - Wenatchee	2023	Food Prodı	Fruit Produ	311423	Dried and I	Tree Top In	Wenatchee	Chelan	Ecology: C	9,775	0	9,765	5	5	0	0	0	0		1	47.48938, -120.31426	Reporter	POINT (-120.31426 47.48938)
Northwest Pipeline Roosevelt C/S - Bickleton	2023	Natural Ga	Natural Ga	486210	Pipeline Tr	The Williar	Bickleton	Klickitat	Ecology: C	11,251	0	9,448	1,797	5	0	0	0	0		1	45.849504	11,251	Covered Ei POINT (-120.08083 45.849504)
Northwest Pipeline C/S - Washougal	2023	Natural Ga	Natural Ga	486210	Pipeline Tr	The Williar	Washouga	Clark	Southwest	10,927	0	9,261	1,661	5	0	0	0	0		1	45.63236,	10,927	Covered Ei POINT (-122.36516 45.63236)
Nutrien US LLC. - Kennewick	2023	Chemicals	Fertilizer P	325311	Nitrogenou	Agrium US	Kennewick	Benton	Benton Cle	13,400	0	8,749	1	4,650	0	0	0	0		1	46.165957	13,400	Covered Ei POINT (-119.017218 46.165957)
Murphy Veneer - Elma	2023	Wood Proc	Other Woo	321212	Softwood \	Murphy Co	Elma	Grays Harl	Olympic Re	8,690	0	8,681	4	5	0	0	0	0		1	47.040323, -123.3343	Reporter	POINT (-123.334339 47.040323)
Mutual Materials Mica Brick Plant - Spokane	2023	Minerals	Other Mine	327120	Clay Buildi	Mutual Ma	Spokane	Spokane	Spokane R	8,596	0	8,587	4	5	0	0	0	0		1	47.55833, -117.2117	Reporter	POINT (-117.2117 47.55833)
Northwest Pipeline Willard C/S - Cook	2023	Natural Ga	Natural Ga	486210	Pipeline Tr	The Williar	Cook	Skamania	Southwest	9,146	0	7,458	1,685	4	0	0	0	0		1	45.778087	9,146	Covered Ei POINT (-121.626311 45.778087)
Milne Fruit Products - Prosser	2023	Food Prodı	Fruit Produ	311411	Frozen Fru	Milne Fruit	Prosser	Benton	Benton Cle	7,387	0	7,379	4	4	0	0	0	0		1	46.202562, -119.7755	Reporter	POINT (-119.775527 46.202562)
Jubitz Corporation - Portland	2023	Supplier	Other Fuel	457120	Other Gas	Jubitz Corp	Portland	Multnomah		7,433	421	6,992	2	19	0	0	0	0				Reporter	
Sierra Pacific Industries - Aberdeen	2023	Wood Proc	Lumber Mi	321113	Sawmills	Sierra Paci	Aberdeen	Grays Harl	Olympic Re	211,895	202,493	6,724	387	2,292	0	0	0	0		3	46.971875, -123.7755	Reporter	POINT (-123.775526 46.971875)
REC Solar Grade Silicon - Moses Lake	2023	Metals	Other Meta	331410	Primary Sn	REC Silicor	Moses Lak	Grant	Ecology: Ea	5,956	0	5,950	3	3	0	0	0	0	Curtailed ir	1	47.138359	5,956	Covered Ei POINT (-119.200383 47.138359)
Northwest Pipeline Plymouth C/S - Plymouth	2023	Natural Ga	Natural Ga	486210	Pipeline Tr	The Williar	Plymouth	Benton	Benton Cle	7,942	0	4,789	3,151	3	0	0	0	0		1	45.9309, -119.41019	Reporter	POINT (-119.41019 45.9309)
Northwest Hardwoods Inc. - Centralia	2023	Wood Proc	Lumber Mi	321113	Sawmills	Littlejohn &	Centralia	Lewis	Southwest	9,004	5,070	3,863	12	60	0	0	0	0		1	46.734454, -122.9919	Reporter	POINT (-122.991963 46.734454)
Bretthauer Oil Company - Hillsboro	2023	Supplier	Other Fuel	424720	Petroleum	Bretthauer	Hillsboro	Washington		4,399	721	3,660	2	16	0	0	0	0				Reporter	
Northwest Hardwoods Inc. - Longview	2023	Wood Proc	Lumber Mi	321113	Sawmills	Littlejohn &	Longview	Cowlitz	Southwest	8,358	4,756	3,535	11	57	0	0	0	0		1	46.114537, -122.9168	Reporter	POINT (-122.916806 46.114537)
Cascade Natural Gas Corporation LDC - statewide	2023	Natural Ga	Natural Ga	221210	Natural Ga	MDU Reso	Kennewick	Benton	Benton Cle	27,198	0	3,025	24,171	2	0	0	0	0		2	46.21875,	27,198	Covered Ei POINT (-119.22987 46.21875)
Air Liquide Electronics Moses Lake Hydrogen Plant	2023	Chemicals	Other Che	325120	Industrial (	Air Liquide	Moses Lak	Grant	Ecology: Ea	2,770	0	2,770	0	0	0	0	0	0		1	47.135844, -119.1996	Reporter	POINT (-119.19962 47.135844)
Analog Devices, Inc. - Camas	2023	Manufactu	Electronics	334413	Semicondı	Linear Tecl	Camas	Clark	Southwest	18,421	0	2,220	1	2,220	3,214	6,382	4,095	289		1	45.598844	18,420	Covered Ei POINT (-122.45232 45.598844)
Pembina Midstream (USA) Inc. - Houston	2023	Supplier	Other Fuel	221210	Natural Ga	Pembina N	Houston	Harris		2,133	0	2,124	3	6	0	0	0	0			2,133	Covered Entity	
Sierra Pacific Industries - Burlington - Mount Vernon	2023	Wood Proc	Lumber Mi	321113	Sawmills	Sierra Paci	Mount Ver	Skagit	Northwest	315,563	309,509	1,919	595	3,541	0	0	0	0		3	48.448553, -122.4346	Reporter	POINT (-122.434613 48.448553)
Rainier Veneer, Inc. - Spanaway	2023	Wood Proc	Other Woo	321212	Softwood \	Rainier Ver	Spanaway	Pierce	Puget Sour	15,208	13,241	1,789	26	152	0	0	0	0		1	47.062059, -122.3189	Reporter	POINT (-122.318981 47.062059)
BB Energy USA LLC	2023	Supplier	Other Fuel	424720	Petroleum	BB ENERG	Houston	Harris		1,694	114	1,548	3	29	0	0	0	0				Reporter	
DH Feeders - Eltopia	2023	Livestock	Cattle Feec	112112	Cattle Feec	Easterday	Eltopia	Franklin	Ecology: Ea	15,999	0	1,333	1,150	13,516	0	0	0	0	Voluntary r	1	46.50919, -118.88120	Reporter	POINT (-118.881203 46.50919)
Puget Sound Energy LDC Facility - Bellevue	2023	Natural Ga	Natural Ga	221210	Natural Ga	Puget Hold	Bellevue	King	Puget Sour	67,479	0	1,060	66,418	1	0	0	0	0		2	47.61345,	67,479	Covered Ei POINT (-122.19454 47.61345)
Alcoa Intalco Works - Ferndale	2023	Metals	Aluminum	331312	Primary Alı	Alcoa Corp	Ferndale	Whatcom	Ecology: In	8,533	0	943	7,590	1	0	0	0	0	Curtailed r	1	48.8455, -:	8,533	Covered Ei POINT (-122.7055 48.8455)
Bio Energy Washington, LLC - Maple Valley	2023	Power Plar	Other Powe	221119	Other Elec	Bio Energy	Maple Vall	King	Puget Sour	11,193	10,496	641	17	39	0	0	0	0		1	47.455871, -122.0418	Reporter	POINT (-122.041817 47.455871)
Riverside Feeders SFL - Kennewick	2023	Livestock	Cattle Feec	112112	Cattle Feec	Easterday	Kennewick	Benton	Benton Cle	17,203	0	612	1,288	15,302	0	0	0	0	Voluntary r	1	45.991872, -119.1364	Reporter	POINT (-119.136497 45.991872)
McKinley Paper Co. - Washington Mill - Port Angeles	2023	Pulp and P	Other Pulp	322121	Paper (exc	McKinley P	Port Angel	Clallam	Olympic Re	186,059	179,313	541	4,153	2,052	0	0	0	0		3	48.134623, -123.4675	Reporter	POINT (-123.467524 48.134623)
Roosevelt Regional Landfill - Roosevelt	2023	Waste	Landfills	562212	Solid Wast	Republic S	Roosevelt	Klickitat	Ecology: C	350,377	1,451	327	348,592	7	0	0	0	0		3	45.807146, -120.1797	Reporter	POINT (-120.179785 45.807146)
Cathcart Landfill - Snohomish	2023	Waste	Landfills	562212	Solid Wast	Snohomisl	Snohomisl	Snohomisl	Puget Sour	23,226	925	193	22,105	3	0	0	0	0		1	47.870014, -122.1182	Reporter	POINT (-122.118284 47.870014)
King County Solid Waste Cedar Hills Landfill - Maple Valley	2023	Waste	Landfills	562212	Solid Wast	King Count	Maple Vall	King	Puget Sour	305,929	56,525	192	249,007	204	0	0	0	0		3	47.462625, -122.0460	Reporter	POINT (-122.046025 47.462625)
SDS Lumber Company - Bingen	2023	Wood Proc	Lumber Mi	321113	Sawmills	SDS Lumb	Bingen	Klickitat	Ecology: C	48,141	47,338	171	91	541	0	0	0	0		2	45.713913, -121.4686	Reporter	POINT (-121.468688 45.713913)
Terrace Heights Landfill - Yakima	2023	Waste	Landfills	562212	Solid Wast	Yakima Co	Yakima	Yakima	Yakima Re	130,876	0	23	130,854	0	0	0	0	0		3	46.610031, -120.3940	Reporter	POINT (-120.39408 46.610031)
Avista Corporation LDC - WA - statewide	2023	Natural Ga	Natural Ga	221210	Natural Ga	Avista Cor	Spokane	Spokane	Spokane R	16,268	0	20	16,249	0	0	0	0	0		1	47.673662, -117.3887	Reporter	POINT (-117.388735 47.673662)
Asotin County Regional Landfill - Clarkston	2023	Waste	Landfills	562212	Solid Wast	Asotin Cou	Clarkston	Asotin	Ecology: Ea	64,147	3,870	17	60,245	14	0	0	0	0		2	46.38463, -117.10598	Reporter	POINT (-117.105985 46.38463)
Cascade Hardwood LLC - Chehalis	2023	Wood Proc	Lumber Mi	321113	Sawmills	Cascade H	Chehalis	Lewis	Southwest	7,607	7,500	7	15	86	0	0	0	0		1	46.635062, -122.9303	Reporter	POINT (-122.930338 46.635062)
Cowlitz County Headquarters Landfill - Castle Rock	2023	Waste	Landfills	562212	Solid Wast	Cowlitz Co	Castle Roc	Cowlitz	Southwest	332,807	15,159	0	317,594	55	0	0	0	0	Emissions	3	46.246902, -122.7722	Reporter	POINT (-122.772284 46.246902)
Vaagen Bros. Lumber, Inc. - Colville	2023	Wood Proc	Lumber Mi	321999	All Other M	Vaagen Bro	Colville	Stevens	Ecology: Ea	33,518	33,076	0	64	378	0	0	0	0		2	48.548525, -117.9154	Reporter	POINT (-117.915469 48.548525)
Hampton Lumber Mills Washington Inc. - Randle	2023	Wood Proc	Lumber Mi	321113	Sawmills	Hampton L	Randle	Lewis	Southwest	57,434	56,677	0	109	648	0	0	0	0		2	46.533743, -121.9179	Reporter	POINT (-121.917906 46.533743)
Cheyne Landfill - Zillah	2023	Waste	Landfills	562212	Solid Wast	Yakima Co	Zillah	Yakima	Yakima Re	47,466	0	0	47,466	0	0	0	0	0		2	46.4785, -120.2688	Reporter	POINT (-120.2688 46.4785)
Avista Corporation - WA State DOE Reporting - statewide	2023	Natural Ga	Natural Ga	221121	Electric Bu	Avista Cor	Spokane	Spokane	Spokane R	1,015	0	0	0	0	0	0	1,015	0		1	47.673486, -117.3885	Reporter	POINT (-117.388514 47.673486)
Cosmo Specialty Fibers Inc - Cosmopolis	2023	Pulp and P	Sulfite Mill	322110	Pulp Mills	Cosmo Sp	Cosmopol	Grays Harl	Ecology: In	2,864	0	0	2,864	0	0	0	0	0	Productior	1	46.952907	2,864	Covered Ei POINT (-123.76211 46.952907)
Sierra Pacific Industries - Centralia	2023	Wood Proc	Lumber Mi	321113	Sawmills	Sierra Paci	Centralia	Lewis	Southwest	39,567	39,000	0	82	486	0	0	0	0		2	46.756413, -122.9954	Reporter	POINT (-122.995433 46.756413)
Waste Management Greater Wenatchee Regional Landfill - East Wenatchee	2023	Waste	Landfills	562212	Solid Wast	Waste Mar	East Wena	Douglas	Ecology: C	59,718	16,811	0	42,847	60	0	0	0	0		2	47.405083, -120.1674	Reporter	POINT (-120.167444 47.405083)
Cowlitz County Tennant Way Landfill - Longview	2023	Waste	Landfills	562212	Solid Wast	Cowlitz Co	Longview	Cowlitz	Southwest	29,327	2,529	0	26,789	9	0	0	0	0	Emissions	2	46.107229, -122.9056	Reporter	POINT (-122.905601 46.107229)
LRI Landfill - Graham	2023	Waste	Landfills	562212	Solid Wast	Waste Cor	Graham	Pierce	Puget Sour	163,427	44,056	0	119,212	159	0	0	0	0		3	46.972405, -122.2927	Reporter	POINT (-122.292799 46.972405)
Hampton Lumber Mills Washington Inc. - Darrington	2023	Wood Proc	Lumber Mi	321113	Sawmills	Hampton L	Darrington	Snohomisl	Puget Sour	83,298	82,200	0	158	940	0	0	0	0		2	48.262797, -121.5976	Reporter	POINT (-121.597608 48.262797)
Thurston County Public Works/WARC - Lacey	2023	Waste	Landfills	562212	Solid Wast	US Govern	Lacey	Thurston	Olympic Re	15,614	0	0	15,614	0	0	0	0	0		1	46.948119, -122.9089	Reporter	POINT (-122.90894 46.948119)
Bonneville Power Administration - WA Only - statewide	2023	Power Plar	Electrical	221121	Electric Bu	US Govern	Vancouver	Clark	Southwest	21,935	0	0	0	0	0	0	21,935	0		1	45.661178, -122.6586	Reporter	POINT (-122.658608 45.661178)
Ponderay Industries - Usk	2023	Pulp and P	Other Pulp	322122	Newsprint	Ponderay I	Usk	Pend Oreil	Ecology: Ea	0	0	0	0	0	0	0	0	0	Facility clo	1	48.289771, -117.2713	Reporter	POINT (-117.271359 48.289771)
Olympic View Sanitary Landfill - Bremerton	2023	Waste	Landfills	562212	Solid Wast	Waste Mar	Bremerton	Kitsap	Puget Sour	65,209	1,536	0	63,667	6	0	0	0	0		2	47.501359, -122.7832	Reporter	POINT (-122.783272 47.501359)
Weyerhaeuser Raymond Lumber - Raymond	2023	Wood Proc	Lumber Mi	321113	Sawmills	Weyerhaeı	Raymond	Pacific	Olympic Re	33,233	32,795	0	63	375	0	0	0	0		2	46.688088, -123.7374	Reporter	POINT (-123.737495 46.688088)
Hampton Lumber Mills Washington Inc. - Morton	2023	Wood Proc	Lumber Mi	321113	Sawmills	Hampton L	Morton	Lewis	Southwest	29,522	29,133	0	56	333	0	0	0	0		2	46.565997, -122.2695	Reporter	POINT (-122.269573 46.565997)
Darling Ingredients Inc - Tacoma	2023	Food Prodı	Meat Prodı	311613	Rendering	Darling Ing	Tacoma	Pierce	Puget Sour	0	0	0	0	0	0	0	0	0	Curtailed ir	1	47.250503, -122.4064	Reporter	POINT (-122.406461 47.250503)
Interfor US, Inc. - Port Angeles	2023	Wood Proc	Lumber Mi	321113	Sawmills	Interfor US	Port Angel	Clallam	Olympic Re	39,544	39,023	0	75	446	0	0	0	0		2	48.103425, -123.5186	Reporter	POINT (-123.518642 48.103425)
Sierra Pacific Industries - Shelton	2023	Wood Proc	Lumber Mi	321212	Softwood \	Simpson L	Shelton	Mason	Olympic Re	59,279	58,498	0	112	669	0	0	0	0		2	47.213448, -123.0965	Reporter	POINT (-123.096517 47.213448)
Boise Cascade Wood Products, LLC. Kettle Falls Lumber - Kettle Falls	2023	Wood Proc	Lumber Mi	321912	Cut Stock,	Boise Cas	Kettle Falls	Stevens	Ecology: Ea	57,275	56,520	0	109	646	0	0	0	0		2	48.609799, -118.0674	Reporter	POINT (-118.067441 48.609799)
Hidden Valley Landfill - Puyallup	2023	Waste	Landfills	562212	Solid Wast	Waste Cor	Puyallup	Pierce	Puget Sour	93,461	1,654	0	91,801	6	0	0	0	0		2	47.095, -122.2878	Reporter	POINT (-122.2878 47.095)
Emerald City Renewables, LLC- Graham	2023	Power Plar	Other Powe	221117	Biomass E	Emerald C	Graham	Pierce	Puget Sour	19,490	19,390	0	30	70	0	0	0	0		1	46.975533, -122.2908	Reporter	POINT (-122.290871 46.975533)
Horn Rapids Sanitary Landfill - Richland	2023	Waste	Landfills	562212	Solid Wast	City of Rict	Richland	Benton	Benton Cle	33,850	3,945	0	29,891	14	0	0	0	0		2	46.346663, -119.3481	Reporter	POINT (-119.348118 46.346663)
Puget Sound Energy T&D - statewide	2023	Power Plar	Electrical	221122	Electric Po	Puget Hold	Bellevue	King	Puget Sour	10,868	0	0	0	0	0	0	10,868	0		1	47.61345, -122.19454	Reporter	POINT (-122.19454 47.61345)
Grant County Landfill 1 - Ephrata	2023	Waste	Landfills	562212	Solid Wast	Grant Cou	Ephrata	Grant	Ecology: Ea	43,957	2,188	0	41,762	8	0	0	0	0		2	47.270759, -119.5737	Reporter	POINT (-119.573764 47.270759)
City of Tacoma Solid Waste Facility - Tacoma	2023	Waste	Landfills	562212	Solid Wast	City of Tac	Tacoma	Pierce	Puget Sour	12,503	5,555	0	6,928	20	0	0	0	0		1	47.223413, -122.4997	Reporter	POINT (-122.499775 47.223413)
Okanogan County Central Landfill - Okanogan	2023	Waste	Landfills	562212	Solid Wast	Okanogan	Okanogan	Okanogan	Ecology: C	17,803	0	0	17,803	0	0	0	0	0		1	48.341148, -119.6201	Reporter	POINT (-119.620109 48.341148)
Port Angeles Hardwood LLC - Port Angeles	2023	Wood Proc	Lumber Mi	321113	Sawmills	Port Angel	Port Angel	Clallam	Olympic Re	21,627	21,342	0	41	244	0	0	0	0		1	48.100872, -123.4857	Reporter	POINT (-123.485745 48.100872)
Guy Bennett Lumber Company - Clarkston	2023	Wood Proc	Lumber Mi	321113	Sawmills	Bennett Lu	Clarkston	Asotin	Ecology: Ea	14,674	14,481	0	28	166	0	0	0	0		1	46.423108, -117.0864	Reporter	POINT (-117.086487 46.423108)
Leichner Landfill - Vancouver	2023	Waste	Landfills	562212	Solid Wast	Clark Cour	Vancouver	Clark	Southwest	620	0	0	620	0	0	0	0	0	Voluntary r	1	45.689202, -122.5733	Reporter	POINT (-122.573372 45.689202)
Stevens County Landfill - Kettle Falls	2023	Waste	Landfills	562212	Solid Wast	Stevens Cc	Kettle Falls	Stevens	Ecology: Ea	9,220	495	0	8,724	2	0	0	0	0		1	48.580583, -118.0875	Reporter	POINT (-118.087594 48.580583)
PUD No 1 of Chelan County - Wenatchee	2023	Power	COU	221118	Other Elec	PUD No 1 (	Wenatchee	Chelan		1,407												Reporter	

Seattle City Light - Seattle	2023	Power	COU	221122	Electric Po	The City of	Seattle	King	268,791	194,361	Covered Entity
The Energy Authority, Inc. - Jacksonville	2023	Power	Marketer	221122	Electric Po	The Energy	Jacksonvill	Duval	19,058		Reporter
Public Utility District No.1 of Cowlitz County	2023	Power	COU	2211	Electric Po	Public Utili	Longview	Cowlitz	88,481	88,481	Covered Entity
Avangrid Renewables LLC - Portland	2023	Power	Electrical	221118	Other Elec	Avangrid, I	Portland	Multnomah	108,329	105,755	Covered Entity
Morgan Stanley Capital Group Inc. - New York	2023	Power	Marketer			Morgan Sta	New York	New York	158,089	26,443	Covered Entity
Big Bend Electric Cooperative, Inc. - Ritzville	2023	Power	COU	2211	Electric Po	Big Bend E	Ritzville	Adams	10,160		Reporter
Northwest Pipeline LLC - Houston	2023	Supplier	Natural Ga	486210	Pipeline Tr	The Williar	Houston	Harris		55,563	Covered Entity
Portland General Electric Company - Portland	2023	Power	IOU	2211	Electric Po	Portland G	Portland	Multnomah	107,381		Reporter
Public Utility District No. 1 of Grays Harbor County - Aberdeen	2023	Power	COU	2211	Electric Po	Public Utili	Aberdeen	Grays Harbor	21,680		Reporter
Inland Power & Light Co - Spokane	2023	Power	COU	221122	Electric Po	Power Distrib	Spokane	Spokane	15,561		Reporter
Public Utility District No. 1 of Clark County - Vancouver	2023	Power	COU	2211	Electric Po	Clark Publi	Vancouver	Clark	98,142	98,142	Covered Entity
City of Richland - Energy Services - Richland	2023	Power	COU	2211	Electric Po	City of Ricl	Richland	Benton	17,933		Reporter
PUD #1 of Snohomish County - Everett	2023	Power	COU	221118	Other Elec	PUD #1 of :	Everett	Snohomish	171,346	168,934	Covered Entity
Peninsula Light Company - Gig Harbor	2023	Power	COU	2211	Electric Po	Jafar Tagh	Gig Harbor	Pierce	11,359		Reporter
Tacoma Power - Tacoma	2023	Power	COU	221122	Electric Po	City of Tac	Tacoma	Pierce	69,131	63,871	Covered Entity
Puget Sound Energy - Bellevue	2023	Power	IOU			Puget Sour	Bellevue	King	2,599,724	2,440,643	Covered Entity
Mason Public Utility District 3 - Shelton	2023	Power	COU	2211	Electric Po	Mason Put	Shelton	Mason	12,413		Reporter
PUD No1 of Clallam County - Clallam	2023	Power	COU	221121	Electric Bu	PUD No1 c	Sequim	Clallam	12,144		Reporter
Public Utility District No. 1 of Lewis County - Chehalis	2023	Power	COU	2211	Electric Po	Public Utili	Chehalis	Lewis	18,253		Reporter
Powerex Corp. - Burnaby	2023	Power	Marketer	424990	Other Misc	Powerex C	Burnaby	Greater Vancouver	62,215	31,772	Covered Entity
Eugene Water & Electric Board - Eugene	2023	Power	COU	221122	Electric Po	Eugene Wa	Eugene	Lane	10,190		Reporter
Macquarie Energy LLC - Houston	2023	Power	Marketer			Macquarie	Houston	Harris	2,592		Reporter
Avista - EPE - Spokane	2023	Power	IOU	221210	Natural Ga	Avista Cor	Spokane	Spokane	1,947,646	1,947,646	Covered Entity
Public Utility District No. 1 of Benton County	2023	Power	COU	2211	Electric Po	Public Utili	Kennewick	Benton	39,537	39,145	Covered Entity
Benton Rural Electric Association - Prosser	2023	Power	COOP	2211	Electric Po	Benton Ru	Prosser	Benton	11,454		Reporter
Clatskanie People's Utility District - Clatskanie	2023	Power	COU	221122	Electric Po	Clatskanie	Clatskanie	Columbia	20,251		Reporter
Gas Transmission Northwest, LLC - Houston	2023	Supplier	Natural Ga	486210	Pipeline Tr	TC Energy	Houston	Harris			Reporter
Public Utility District No. 1 of Douglas County - East Wenatchee	2023	Power	COU	221111	Electric po	Public Utili	East Wena	Douglas	8,115		Reporter
Shell Energy North America US LP	2023	Power	Marketer	221122	Electric Po	Shell USA,	San Diego	San Diego	332,095	105,777	Covered Entity
PacifiCorp - Portland	2023	Power	IOU	221122	Electric Po	Berkshire I	Portland	Multnomah	1,914,409	1,913,306	Covered Entity
TransAlta Energy Marketing (U.S.) Inc.	2023	Power	Marketer	221122	Electric Po	TransAlta I	Calgary	MD of Foothills No. 31	10,498		Reporter
Public Utility No. 1 of Franklin County - Pasco	2023	Power	COU	2211	Electric Po	Public Utili	Pasco	Franklin	20,269		Reporter
Brookfield Renewable Trading and Marketing LP - New York	2023	Power	Marketer	221122	Electric Po	Brookfield	New York	New York	6,193		Reporter
Grant County PUD #2 -Ephrata	2023	Power	COU	221122	Electric Po	Grant Cou	Ephrata	Grant	77,653	77,653	Covered Entity

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-112:
Energy Facility Site Evaluation Council 2007 Adjudicative Order

BEFORE THE STATE OF WASHINGTON

ENERGY FACILITY SITE EVALUATION COUNCIL

In the Matter of Application No. 2006-01	**ADJUDICATIVE ORDER NO. 2** **COUNCIL ORDER NO. 833**
ENERGY NORTHWEST	**ORDER: STAYING ADJUDICATIVE PROCEEDING**
PACIFIC MOUNTAIN ENERGY CENTER POWER PROJECT	

Nature of the Proceeding

This matter involves Application No. 2006-1 submitted by Energy Northwest ("ENW") for certification of a site at Kalama, Washington in Cowlitz County under RCW 80.50. ENW proposes to construct the Pacific Mountain Energy Center ("PMEC") a combined cycle gasification facility for the production of electrical energy. Chapter 80.50 RCW gives the Energy Facility Site Evaluation Council ("EFSEC" or "the Council") the authority to make a recommendation to the governor as to whether the State, by action of the Governor, should enter into a site certification agreement with the applicant that would authorize the construction and operation of PMEC subject to the terms of the agreement.

At this moment,[1] ENW proposes to construct PMEC as a 793 megawatt electrical generating facility. PMEC is proposed to operate on synthetic gas produced from petroleum coke, a byproduct of refining, or coal. ENW filed this application initially on September 12, 2006, before the enactment of Engrossed Substitute Senate Bill 6001 (ESSB 6001), codified as RCW 80.80. ENW was the first in Washington State to propose an Integrated Gasification Combined Cycle (IGCC) project with carbon sequestration. The project involves environmental technology that seeks to minimize carbon emissions, to recapture byproducts such as sulfur, and to utilize as its fuel, products such as petroleum coke, a refinery waste product that might otherwise not be recycled, and coal.

ESSB 6001, RCW 80.80

Approximately seven months after ENW filed its application, the legislature enacted and the Governor signed ESSB 6001 of the 2007 legislative session. The bill is codified as chapter 80.80 of the Revised Code of Washington.

[1] Its present proposal differs somewhat from the proposal in its original filing; the applicant intends to file an update soon that will set out in accurate detail its current proposal. An application may evolve during review (*see,* WAC 463-60-116).

The new law imposes conditions on pending applications. RCW 80.80.040(11) requires new facilities generating more than 1100 pounds of greenhouse gases per megawatt hour of electricity to sequester greenhouse gases to this level or below. The project must satisfy the criteria of RCW 80.80(11)(a)-(f) although it is not required to comply with rules being separately promulgated by the Department of Ecology and the Council.[2]

The statute, RCW 80.80.040(13), requires that an application pending on the date the law became effective[3] must include a carbon sequestration plan, referred to herein as a greenhouse gas reduction plan (GGRP), that demonstrates how the project will meet all of the requirements of RCW 80.80(11). RCW 80.80(13) also requires the applicant to make a good faith effort to implement the plan. Only after preparing a detailed sequestration plan, receiving a site certification agreement, and making a good faith effort to implement the plan, may an applicant who finds implementation "not feasible" be excused from its terms and allowed to purchase greenhouse gas offsets.[4]

Energy Northwest's Greenhouse Gas Reduction Plan

ENW filed the GGRP on July 30, 2007. The GGRP explained ENW's view that a plan such as contemplated by the statute is impossible to prepare at present based on the technological and economical infeasibility of geological sequestration. Instead, ENW presented a proposal to

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[2] (11) In adopting the rules for implementing this section, the energy facility site evaluation council and the department shall include criteria to be applied in evaluating the carbon sequestration plan, for base load electric generation that will rely on subsection (7) of this section to demonstrate compliance, but that will commence sequestration after the date that electricity is first produced. The rules shall include but not be limited to:

(a) Provisions for financial assurances, as a condition of plant operation, sufficient to ensure successful implementation of the carbon sequestration plan, including construction and operation of necessary equipment, and any other significant costs;

(b) Provisions for geological or other approved sequestration commencing within five years of plant operation, including full and sufficient technical documentation to support the planned sequestration;

(c) Provisions for monitoring the effectiveness of the implementation of the sequestration plan;

(d) Penalties for failure to achieve implementation of the plan on schedule;

(e) Provisions for an owner to purchase emissions reductions in the event of the failure of a sequestration plan under subsection (13) of this section; and

(f) Provisions for public notice and comment on the carbon sequestration plan.

[3] This is the only application subject to these terms of the law.

[4] (13) A project under consideration by the energy facility site evaluation council by July 22, 2007, is required to include all of the requirements of subsection (11) of this section in its carbon sequestration plan submitted as part of the energy facility site evaluation council process. A project under consideration by the energy facility site evaluation council by July 22, 2007, that receives final site certification agreement approval under chapter 80.50 RCW shall make a good faith effort to implement the sequestration plan. If the project owner determines that implementation is not feasible, the project owner shall submit documentation of that determination to the energy facility site evaluation council. The documentation shall demonstrate the steps taken to implement the sequestration plan and evidence of the technological and economic barriers to successful implementation. The project owner shall then provide to the energy facility site evaluation council notification that they shall implement the plan that requires the project owner to meet the greenhouse gases emissions performance standard by purchasing verifiable greenhouse gases emissions reductions from an electric generating facility located within the western interconnection, where the reduction would not have occurred otherwise or absent this contractual agreement, such that the sum of the emissions reductions purchased and the facility's emissions meets the standard for the life of the facility.

prepare a specific plan at some future time, perhaps as late as 2020, when geological sequestration becomes a proven technology for use by power plants and a number of asserted technological, engineering, and legal questions have been answered. In the interim, ENW proposed to consider offsets based on assumptions that it enumerated in its GGRP.

The Council convened a prehearing conference on September 20, 2007 at Kalama, Washington to begin the adjudication and advised the parties that it had questions about the GGRP and its sufficiency. It informed the parties of its questions, set a briefing schedule, and a tentative schedule for oral argument. It provided the text of the questions to parties as an attachment to the prehearing conference order.[5]

The parties presented briefs on schedule, and the Council determined that the quality of the briefs was sufficiently high that it felt oral argument to be unnecessary.

The following persons provided opening and answering briefs to the Council.

Applicant:	**ENERGY NORTHWEST** by Elizabeth Thomas, Attorney at Law, K&L Gates LLP, Seattle.
Counsel for the Environment:	**Michael Tribble**, Assistant Attorney General (AAG), Olympia.
Council Member Agencies:	**Washington Department of Ecology** by Laura Watson, Assistant Attorney General, Olympia.
	Washington Department of Community Trade and Economic Development by Alice Blado, Assistant Attorney General.
Petitioners for Intervention:	**Columbia Riverkeeper, Willapa Hills Audubon Society, Rosemere Neighborhood Association**, by Scott Jerger, Attorney, Field Jerger, LLP, Portland, Oregon.
	Northwest Energy Coalition, Washington Environmental Council, Sierra Club, by Stephen Mashuda, Attorney, Joshua Osborne-Klein, Attorney, Jan Hasselman, Attorney, Earthjustice, Seattle.

[5] Appendix I.

Sufficiency of the GGRP

The most significant question – and the only question posed to the parties that the Council will address in this order[6] – is whether the GGRP as proposed legally complies on its face with the requirements of the statute.

We determine as a Council, and without dissent, that the ENW GGRP fails to meet the minimum requirements of the law, that it is therefore insufficient as a matter of law, that its provisions cannot be supplemented to the level of minimal sufficiency by mere revisions, and that its flaws are pervasive and affect the processing of the entire application. Therefore, we stay the adjudicative process and direct the Council staff to suspend application processing pending action by the applicant to cure the present flaws.

1. The Basic Flaw.

The basic flaw in ENW's GGRP is that it is not a plan at all in terms of the statute – it does not identify specific steps it will take to implement sequestration. Instead, it is a plan to make a plan, and it vows to begin making specific steps toward implementing geological sequestration at some future time, after geological sequestration becomes commercially accepted for use in reducing emissions of fossil-fueled power plants. It proposes that eventually, at some indefinite future time, it will seek to develop a specific plan for accomplishing the purposes of the statute. In the meantime, it argues, after the fifth year of operation, it may purchase offsetting greenhouse gas emission rights from unspecified sources because a specific plan is futile and it need not make a good faith effort to comply with the letter of the statute.

The reason this is a fundamental flaw is that it asks the Council to invalidate the statute – an action that is clearly beyond the power of an administrative agency.[7] This is not an ambiguous statute, which might be cured by interpretation of its terms. Instead, the statute is detailed and specific in its requirements. The applicant must make specific plans for specific actions to accomplish a specific goal – geologic or other approved sequestration of greenhouse gases – and receive from the Governor a Site Certification Agreement, before it can ask for relief by the purchase of offsets. Then, only after ENW has made a good faith effort to implement the plan, and only after the Council has agreed that implementation is "not feasible," may it be excused from compliance with plan implementation and allowed to purchase offsetting emission rights.

ENW argues that sufficiency of the GGRP is a factual issue that must be determined only after an evidentiary hearing. We strongly disagree. We need only look to the statute and the plan that ENW presented to determine whether the plan contains the elements that the statute requires.

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[6] In light of our decision on GGRP sufficiency, we find it unnecessary and inappropriate to address the remaining questions. The parties' briefs are available to us for consideration at a later time, and parties may address the remaining questions in their evidentiary presentations, as they choose and as may be appropriate.

[7] An agency has some discretion to interpret an ambiguous statute which sets forth its authority; however, it may not alter or amend the provisions of such authorizing legislation and must interpret them within the statute's framework and policy. *Burlington Northern v. Johnston*, 89 Wn.2d 321, 572 P.2d 1085 (1977)

We determine that the GGRP simply does not contain the elements required by statute, not that a plan containing the required elements is inadequate in its measures.[8]

2. Futility or Impossibility of Compliance.

ENW argues that compliance with the statute is futile. While futility may be true from its perspective, which would require a fully developed carbon sequestration industry before literal compliance with the statute is mandated, it is not true from the standpoint of the other parties. They point out that some projects must be within the first wave of technological development – if all waited until a technology became mainstream, technology would never reach mainstream. They also note that sequestration technology is mature in other high-volume applications, such as extraction of oil from wells.

Futility is also not true from the plain language and the clear meaning of the statute. The other parties point out that the statute was enacted specifically to deal with applications in ENW's present situation and that the legislature is presumed to know the meaning and the application of its enactments. This is not an ambiguous statute, which might be susceptible of interpretation. The law is clear and specific in its application to this project. We will not interpret the statute to disregard the plain meaning of the legislature.

ENW argues that it made a good faith effort to comply with the statute. We do not impugn its motives. The test we must apply, however, is not whether it has made a good faith effort, but whether its GGRP complies with the clear terms of the law. We determine that it does not.

ENW proposes application of the "doctrine of impossibility," citing a case in which physical incapacity excused a teacher from the duty to teach,[9] and it argues that under terms of the "vested rights doctrine," the law is invalid in application to PMEC because the application was filed before the law became effective and because of "constitutional principles of fairness and due process."[10] ENW does not contend that we have jurisdiction to invalidate the law on those bases and it does not address whether the vested rights principle also applies to matters such as this, which affect the public health, safety and welfare.

3. Specific Elements.

RCW 80.80.040(13) applies to ENW's application to require a GGRP with five specific elements identified in RCW 80.80.040(11): financial assurances, provision for geological or other approved sequestration, monitoring to ensure GGRP effectiveness, penalties for failure to achieve implementation, and provisions for public notice and comment. The parties all agree that adopting a GGRP through the EFSEC application process satisfies the requirement for public notice and comment. They disagree on whether the applicant has met the other requirements.

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[8] ENW's argument that it "addresses" the topics in RCW 80.80.040(11) begs the question – subsection 13 requires development of a plan, not a statement addressing issues and offering at some time later to develop a plan to resolve them.

[9] *O'Neal v. Colton Consolidated Sch. Dist.*, 16 Wn.App. 488, 557 P.2d 11 (1976).

[10] *Weyerhaeuser v. Pierce County*, 95 Wn.2d 883, 976 P.2d 1279 (1999).

a. Geological sequestration.

The principal flaw in the GGRP is its failure to present a plan to achieve geological sequestration. It does not detail specific actions ENW will take. Instead, the GGRP merely states that because geological sequestration of power plant emissions is not a conventional technology, and because uncertainties exist in technical and legal aspects of geological sequestration, it will not begin to prepare a specific plan until technical and legal questions are resolved. In this regard, ENW's GGRP fails to meet the plain language of the statute – it is a plan to prepare a plan at some indefinite later date.

b. Financial assurances.

The statute requires specific financial assurances in the GGRP.[11] ENW's financial assurance merely identifies the applicant's status as a public entity and proposes that its bonding power will enable it to meet costs of geological sequestration. It does not identify costs of construction and operation of necessary equipment, or any other specific significant costs. It does not demonstrate that its bonding power is unlimited or that it will in the future be capable of using its bonding power to meet any costs that may arise.

c. Monitoring.

The GGRP does not identify specific means of monitoring the effectiveness of a sequestration plan. Instead, it states that ENW will develop a monitoring plan at a later time, subject to EFSEC approval.

d. Penalties.

The GGRP does not identify penalties for failing to achieve implementation of the sequestration plan on schedule. Instead, it opines that costs the company would incur would constitute effective penalties. We disagree; had the legislature intended the result urged, no mention of penalties would have been needed in the law.

e. Offsets, in the event of sequestration failure.

The statute requires the GGRP to include provisions for the purchase of emissions reductions in the event of failure, in implementing the sequestration plan. The statute also requires documentation of that failure to be submitted to the Council, prior to purchasing verifiable greenhouse gases emissions reduction offsets. ENW identified the requirement, and stated that if necessary it would secure offsets. The statements do not rise to the level of a "plan" – they merely identify the requirement and postulate that ENW would be able to secure offsets.

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[11] RCW 80.80.040(11)(a) requires ". . . financial assurances, as a condition of plant operation, *sufficient to ensure successful implementation of the carbon sequestration plan, including construction and operation of necessary equipment, and any other significant costs.*" (Emphasis added).

4. Conclusion.

In sum, the plain reading of the statute demands a carbon sequestration plan, with specifics, and ENW has provided only a general statement of intention that it will begin creating such a plan in the future at some indefinite time. In its brief, ENW calls this proposal "adaptive management," under a practice that allows details of compliance to be developed through different measures, over time, allowing learning from and improving upon compliance measures. RCW 80.80 does not allow adaptive management in lieu of clear statutory requirements, and ENW's proposal is a proposal to develop goals and measures later. It is not adaptive management, which pursues specific goals through clearly identified means.

We conclude that ENW's proposed greenhouse gas reduction plan fails to meet the requirements of the statute, and must be rejected.

The GGRP is a statutory requirement that is essential to this application. It is irrevocably tied to the specific proposal in the application. And the proffered GGRP misses the mark by a wide margin – it is not susceptible of a few minor fixes to render it even minimally sufficient. For that reason, we stay the adjudicative proceeding and find it wisest to stop the application processing until ENW proposes a cure that addresses lack of an adequate GGRP.

We acknowledge ENW's frustration.[12] The proposed project has been affected by the actions of the legislature. Relief however, is not available from EFSEC.

We acknowledge ENW's pressing need to satisfy its members' power requirements beginning in 2012, and trust that it will act promptly to address its situation in a way that allows it, and the Council, to resume application processing in a timely manner.

It is so ordered.

Dated at Olympia, Washington, and effective this 27th day of November, 2007.

WASHINGTON STATE ENERGY FACILITY
SITE EVALUATION COUNCIL



James O. Luce, Chair

[12] See ENW's Reply Brief at p. 14 citing Federalist No. 44 at 301(J. Madison)(J. Cooke ed. 1961.

Appendix I

Council Questions About
The Pacific Mountain Energy Center
Greenhouse Gas Reduction Plan (GGRP)

When briefing these questions, please state reasons for your conclusions.

1. Rulemaking
   a. Does ESSB 6001 require that the PMEC gasification plant proceedings be stayed until "....the energy siting council and the department....adopt rules...to implement and enforce the greenhouse gases emissions performance standard"?
   b. If rulemaking need not be completed under Section 5(10) of ESSB 6001 prior to consideration of the PMEC project because the project was pending before EFSEC on the effective date of ESSB 6001, does the greenhouse gas plan "[include] all of the requirements of subsection 11 of [Section 5] ..."? If so, why; if not, why not, and, if not, what specific additional elements are needed.

2. Sufficiency of the PMEC greenhouse gas reduction plan (GGRP).
   a. Is this applicant's GGRP legally sufficient for the application to proceed?
   b. Does the proposed PMEC greenhouse gas plan, on its face, "...work in unison with the state's carbon dioxide mitigation policy, chapter 80.70 RCW and its related rules, for fossil fueled thermal electric generation facilities in the State"?[13] Why or why not, and if not, what kind of modification of the plan would be needed for such "unison"?
   c. Is the PMEC GGRP, as submitted, a sufficient "good faith" demonstration of compliance to warrant issuance of a conditional certificate allowing construction? If not, what elements are lacking?
   d. If EFSEC were to issue a "final site certification agreement under authority of RCW 80.50," would the submitted sequestration plan be capable of a demonstration of "good faith effort to implement [the law]," and why or why not, with respect to the following elements:
      - Financial assurances under Section 5(11)(a)
      - Geological or "other approved sequestration" commencing within 5 years of commercial operation under Section 5(11(b) [Section V.A. of PMEC Plan]
      - Monitoring under Section 5(11)(c)
      - Penalties for failure to achieve implementation under Section 5(11) (d). If the project could not operate until EFSEC finds compliance, would that be a sufficient penalty?

[13] ESB 6001, Section 1(e).

- Provisions for the purchase of offsets under Section 5(11)(e) [Section V.B. of PMEC Plan]

e. How may an applicant meet the requirement that "full and sufficient documentation to support the planned sequestration" if technology to support plans for geological sequestration does not yet exist?

f. The applicant proposes to run the plant on natural gas for an initial period and, if gasification is not feasible, to continue firing it with natural gas indefinitely. Is this an adequate alternative, assuming that emissions under natural gas operations are anticipated to be lower than under gasification? If it operates as a natural gas-fired facility, will it comply with the requirements of ESSB 6001 and RCW 80.70?

3. Timing of GGRP support.

a. Must the applicant submit a facially adequate GGRP before the adjudicative process may begin? May the Council delay the adjudicative review of an application until the applicant submits a legally sufficient GGRP?

b. If there is doubt under WAC 463-60-010 about the sufficiency of the GGRP as submitted, should further application processing be halted until the applicant submits a plan that is arguably adequate on its face, or may the applicant agree to modify its proposed GGRP during the hearing process under WAC 463-60-116? Why?

c. If the Council rules that a GGRP is deficient on its face and the applicant may not supplement it during the adjudication, may the applicant reapply or resubmit its application with a revised plan and still be vested under the exemption of subsection 5(13) of ESSB 6001?

4. Conditional permit possibility.

a. Must an applicant submit a legally sufficient GGRP before the Council submits a draft site certification agreement to the Governor, or may the Council condition operating authority on later approval of such a plan, prior to operation?

b. Is the issue of <u>final</u> "gas reduction" compliance with ESSB 6001 premature to consider at this time, given EFSEC's authority to issue a conditional certificate allowing construction, while reserving approval of commercial operation until construction is completed and all gas reduction goals established?

Pacific Mountain Energy Center Power Project Application No. 2006-01
Service List November 7, 2007

Unless otherwise indicated, copies must be served on all persons on this list.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-113:
Ecology-TransAlta Agreed Order on Centralia Cleanup

State of Washington
Department of Ecology

In the Matter of Remedial Action by:
TransAlta Centralia Generation LLC for: TransAlta Centralia
Agreed Order
No. DE 24235

To: Mickey Dreher, Vice President, Centralia
913 Big Hanaford Rd, Centralia, WA 98531-9101

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Exhibit A Location Diagram
Exhibit B Scope of Work

1. Introduction

The mutual objective of the State of Washington, Department of Ecology (Ecology) and TransAlta Centralia Generation LLC (TransAlta) under this Agreed Order (Order) is to provide for remedial action at a facility where there has been a release or threatened release of hazardous substances. This Order requires TransAlta to conduct a remedial investigation and feasibility study, develop a draft cleanup action plan, and implement the final cleanup plan for the Site. Ecology believes the actions required by this Order are in the public interest.

2. Jurisdiction

This Order is issued pursuant to the Model Toxics Control Act (MTCA), RCW 70A.305.050(1).

3. Parties Bound

This Agreed Order shall apply to and be binding upon the Parties to this Order, their successors and assigns. The undersigned representative of each Party hereby certifies that he or she is fully authorized to enter into this Order and to execute and legally bind such Party to comply with this Order. TransAlta agrees to undertake all actions required by the terms and conditions of this Order. No change in ownership or corporate status shall alter TransAlta's responsibility under this Order. TransAlta shall provide a copy of this Order to all agents, contractors, and subcontractors retained to perform work required by this Order, and shall ensure that all work undertaken by such agents, contractors, and subcontractors complies with this Order.

4. Definitions

Unless otherwise specified herein, the definitions set forth in RCW 70A.305, WAC 173-204 and WAC 173-340 shall control the meanings of the terms in this Order.

4.1 **Site**: The Site is referred to as TransAlta Centralia. The Site constitutes a facility under RCW 70A.305.020(8). The Site is defined by where a hazardous substance, other than a consumer product in consumer use, has been deposited, stored, disposed of, or placed, or otherwise come to be located. Based upon factors currently known to Ecology, the

Site is generally located in the vicinity of 913 Big Hanaford Rd, Centralia, WA as shown in the Location Diagram (Exhibit A).

4.2 **Parties**: Refers to the State of Washington, Department of Ecology and TransAlta.

4.3 **Potentially Liable Persons (PLP(s))**: Refers to TransAlta.

4.4 **Agreed Order or Order**: Refers to this Order and each of the exhibits to this Order. All exhibits are integral and enforceable parts of this Order.

5. Findings of Fact

Ecology makes the following findings of fact, without any express or implied admissions of such facts by TransAlta:

5.1 Based upon factors currently known to Ecology, the Site is generally located in the vicinity of 913 Big Hanaford Rd, Centralia, WA and includes at a minimum, Lewis County parcels 23340001000, 23340002002, 23340003000, 23340004000, 23340005001, 23340005002, 23340005003, 23340005004, 23436000000, 23345000000, 23355001006, 23355001007, 23355001008, 23355002002 as shown in the Location Diagram (Exhibit A).

5.2 The property has been developed for use as a coal-fired power generation facility since 1968, with the first boiler commissioned in 1971 and the second coming online in 1972. Containment ponds at the facility were constructed in the 1970s. Multiple utility companies owned and operated the facility until TransAlta purchased it in 2000. Prior to its use as a coal-fired power generation facility, the land was primarily agricultural or forested/undeveloped.

5.3 TransAlta is obligated to cease operation of its coal-fired boilers by December 31, 2025, per Revised Code of Washington (RCW) 80.80.040(3)(c), RCW 80.80.100, RCW 80.82.010, and the Memorandum of Understanding executed between TransAlta and the State of Washington on December 23rd, 2011, as further amended on July 13, 2017(2011 MOA). TransAlta retired the first coal-fired boiler in 2020 and plans to retire the second coal-fired boiler in December 2025. TransAlta is actively exploring opportunities to convert the unit to a natural gas peaking facility to support reliability and regional resource adequacy.

5.4 As part of the closure requirements for the facility, RCW 80.82.010(1)(d) requires TransAlta to provide among other things "decommissioning and site restoration plan

that addresses restoring physical topography, cleanup of all hazardous substances on the site, potential future uses of site following restoration, and coordination with local and community plans for economic development in the vicinity of the site".

5.5 As part of the transfer of the facility from PacificCorp to TransAlta, PacificCorp disclosed the following environmental issues related to hazardous substances at the facility:

- In 1987, a leak in the start-up fuel oil supply line was identified. The leak was near the northwest corner of Unit #1 Lodge-Cottrell precipitator. An investigation in 1998 documented diesel contamination ranging up to 845 parts per million (ppm) at a depth of 5 feet below ground surface (bgs). A subsequent report on the extent of the contamination was produced by Dames & Moore in July 2000 (D&M 2000).

- In 1989, a leak in the fuel oil supply line was identified in the area north of the #1 ID fans.

- In 1994, the reservoir for the hydraulic hoist in the heavy equipment shop was discovered to have a leak. A report was reportedly produced titled, *Heavy Equipment Rebuild Shop Subsurface Soil Investigation* report, dated June 15, 2001.

- In 1994, there was a leak in the startup fuel oil return line in the area south of the main fuel oil tanks.

- On November 23, 1999, there was a release of approximately 2,500 gallons of fuel oil from the warm-up oil supply line. This release was reported to the EPA and Ecology. A site investigator from Ecology visited the plant.

- A memo dated December 2, 2003, by PacifiCorp noted a "tarry substance" consistent with petroleum-based paints and solvents was discovered during pipe repair activities of underground pipes located to the north of the coal and ash shop west of the sewage treatment pond. The memo states:

  "All of the tarry substance visible was excavated and disposed of with the contaminated soil from the scrubber construction area. Based on the results from the soil samples obtained prior to the excavation activities it appears that no additional work activities are required for this site."

A notification prepared by PacifiCorp stated that all the leaks had been repaired and remediation activities were complete.

5.6 TransAlta conducted post-sale investigations between 2000 and 2004. These investigations identified the following:

TPH concentrations in surface soil samples exceeded the MTCA Method A Cleanup Level in four of the samples (SS-DMB-2 to SS-DMB-5). TPH was not detected at

concentrations exceeding the MTCA Method A Cleanup Level in the subsurface soil samples.

Diesel-range TPH concentrations in groundwater exceeded the MTCA Method A Cleanup Level in samples collected from the monitoring wells. Arsenic concentrations exceeded the MTCA Method B Cleanup Level in groundwater samples collected from the wells. Lead concentrations exceeded the MTCA Method A Cleanup Level in samples collected from three wells located in the Main Plant Area and in well MW-P5, located in the Effluent Ponds area. Beryllium and chromium concentrations exceeded the MTCA Method B Cleanup Level and Method A Cleanup Level, respectively, in groundwater samples collected from wells MW-P3 and MW-P5. VOCs were not detected at concentrations exceeding MTCA Method A or B Cleanup Levels.

TPH was not detected in the accumulated solid samples in the Coal Runoff Pond at concentrations exceeding the MTCA Method A Cleanup Level, but TPH concentrations in the three South Effluent Pond samples did. Methylene chloride was detected at a concentration exceeding the MTCA Method A Cleanup Level in samples CR-Pond-A and CR-Pond-C. Metal concentrations were less than the Washington State Background Metals soil concentrations except copper and zinc. Beryllium was detected at a concentration exceeding the MTCA Method B Cleanup Level.

Three monitoring wells (MW-P3, MW-P4, and MW-P5) were sampled and analyzed for total and dissolved arsenic, beryllium, chromium, and lead. Arsenic was detected at concentrations exceeding the MTCA Method A and B Cleanup Levels.

PacifiCorp notified TransAlta of the status of ongoing remediation activities in *Current Project Status and Summary of Closed Work Activities*, dated February 23, 2004. According to the report, the scrubber construction area, the warm-up fuel line spill area, and a small area identified as the north trench were remediated to Ecology standards.

5.7 In 2003 TransAlta prepared a report to evaluate hydrogeologic conditions at the facility in accordance with their NPDES permit. A groundwater sample collected from well AFT 313 contained dissolved manganese and iron concentrations exceeding the MTCA Method A Cleanup Levels.

5.8 TransAlta performed a limited groundwater sampling event, in 2003, on wells located on the facility as well as on the neighboring Centralia Coal Mine property. Solvents tetrachloroethene (PCE) and trichloroethene (TCE) and breakdown products 1,1-dichloroethene (1,1-DCE), trans-1,2-dichloroethene, cis-1,2-dichloroethene, and vinyl

chloride were observed at concentrations in select wells exceeding their respective cleanup levels.

5.9 In 2014, a wastewater sample collected from Outfall was found to contain a mercury concentration that exceeded the NPDES permit surface water quality criterion. The source of the mercury was determined to be coal and products from its combustion.

5.10 From 2017 to present, multiple toxicity tests have been conducted on the TransAlta effluent at Outfall 001. A review of the effluent chemistry data in 2021 indicated that copper, and possibly zinc or hexavalent chromium, could contribute to chronic toxicity to *Ceriodaphnia dubia*.

5.11 In 2021, approximately 1,000 gallons of transformer oil was spilled onto soil, a roadway, and a holding pond. The spill was reported to Ecology (FS ID 119916). Absorbent material and a vacuum truck were used to remove pooled product from the roadway and soils around the transformer. Impacted soils were removed and taken to Marine Vacuum Services in Seattle, Washington, for disposal.

5.12 In response to the requirements of the 2011 MOA , TransAlta conducted a series of remedial investigations at the facility. The results of these investigations (Remedial Investigation Report, TransAlta Centralia Generation, LLC, May 2025) found the following:

There are six contaminants of concern found above applicable cleanup levels for soil at the Site. These are arsenic, barium, cadmium, copper, selenium, and zinc.

There are nine contaminants of concern found above applicable cleanup levels for groundwater at the Site. These are arsenic, chromium, copper, manganese, selenium, zinc, 1-methylnaphthalene, total petroleum hydrocarbons – diesel range, and vinyl chloride.

There are six contaminants of concern found above applicable cleanup levels in sediment at the facility. These are arsenic, cadmium, chromium, mercury, nickel, and selenium.

6. Ecology Determinations

Ecology makes the following determinations, without any express or implied admissions of such determinations (and underlying facts) by TransAlta.

6.1 TransAlta is an "owner or operator" as defined in RCW 70A.305.020(22) of a "facility" as defined in RCW 70A.305.020(8). Specifically, TransAlta is the current owner and operator of the property within the Site where there has been a release of hazardous substances to the environment.

6.2 Based upon all factors known to Ecology, a "release" or "threatened release" of "hazardous substance(s)" as defined in RCW 70A.305.020(32), and (13), respectively, has occurred at the Site.

6.3 Based upon credible evidence, Ecology issued a PLP status letter to TransAlta dated September 4, 2025, pursuant to RCW 70A.305.040, .020(26), and WAC 173-340-500. By letter dated October 8, 2025, TransAlta voluntarily waived its rights to notice and comment and accepted Ecology's determination that TransAlta is a PLP under RCW 70A.305.040.

6.4 Pursuant to RCW 70A.305.030(1), .050(1), Ecology may require PLPs to investigate or conduct other remedial actions with respect to any release or threatened release of hazardous substances, whenever it believes such action to be in the public interest. Based on the foregoing facts, Ecology believes the remedial actions required by this Order are in the public interest.

7. Work to be Performed

Based on the Findings of Fact and Ecology Determinations, it is hereby ordered that TransAlta take the following remedial actions at the Site. The area within the Site where remedial action is necessary under RCW 70A.305 is described in the Remedial Action Location Diagram (Exhibit A). These remedial actions must be conducted in accordance with WAC 173-340 and 173-204:

7.1 TransAlta will complete the remedial investigations they have begun prior to the Order, including addressing Ecology's comments on the submitted draft Remedial Investigation Report. TransAlta shall fully define the nature and extent of contamination at the Site, in a manner that meets with Ecology's approval and that meets the applicable requirements of MTCA and Chapters 173-340 and 172-204 WAC, and identify and analyze cleanup action alternatives to address contaminants above applicable levels. TransAlta shall also produce a Supplemental Remedial Investigation Work Plan, Remedial Investigation report (RI), Feasibility Study (FS), and draft Cleanup Action Plan (DCAP). TransAlta also agrees to implement a final cleanup action plan (fCAP). Work under this order must include the entire Site where a hazardous substance from a release has come to be located, including areas surrounding the coal plant property that may be subject to aerial deposition of contaminants. The work is to

be conducted in accordance with the schedule and terms of the Scope of Work and Schedule, Exhibit B, and all other requirements of this Order." The following naming conventions shall be used for documents: Agency Review Draft (designation for the first time Ecology receives a document); Public Review Draft (designates a document ready for public comment); Final (designation for a document after public comment and Ecology approval); and the preliminary Draft Cleanup Action Plan (designation for the Subject PLP(s)'s version of the DCAP).

7.2 If TransAlta learns of a significant change in conditions at the Site, including but not limited to a statistically significant increase in contaminant and/or chemical concentrations in any media, TransAlta, within seven (7) days of learning of the change in condition, shall notify Ecology in writing of said change and provide Ecology with any reports or records (including laboratory analyses, sampling results) relating to the change in conditions.

7.3 Pursuant to WAC 173-340-440(11), TransAlta shall maintain sufficient and adequate financial assurance mechanisms to cover all costs associated with the operation and maintenance of the remedial action at the Site, including institutional controls, compliance monitoring, and corrective measures.

7.3.1 Within sixty (60) days of the fCAP, TransAlta shall submit to Ecology for review and approval an estimate of the costs under this Order for operation and maintenance of the remedial actions at the Site, including institutional controls, compliance monitoring and corrective measures. Within sixty (60) days after Ecology approves the aforementioned cost estimate, TransAlta shall provide proof of financial assurances sufficient to cover all such costs in a form acceptable to Ecology.

7.3.2 TransAlta shall adjust the financial assurance coverage and provide Ecology's project coordinator with documentation of the updated financial assurance for:

7.3.3 Inflation, annually, within thirty (30) days of the anniversary date of the fCAP; or if applicable, the modified anniversary date established in accordance with this section, or if applicable, ninety (90) days after the close of TransAlta's fiscal year if the financial test or corporate guarantee is used.

7.3.4 Changes in cost estimates, within thirty (30) days of issuance of Ecology's approval of a modification or revision to the cleanup action plan (CAP) that result in increases to the cost or expected duration of remedial actions. Any

adjustments for inflation since the most recent preceding anniversary date shall be made concurrent with adjustments for changes in cost estimates. The issuance of Ecology's approval of a revised or modified CAP will revise the anniversary date established under this section to become the date of issuance of such revised or modified CAP.

7.4 All plans or other deliverables submitted by TransAlta for Ecology's review and approval under the Scope of Work and Schedule (Exhibit B) shall, upon Ecology's approval, become integral and enforceable parts of this Order. TransAlta shall take any action required by such deliverable.

7.5 Pursuant to WAC 173-340-430, an interim action is a remedial action that is technically necessary to reduce a threat to human health or the environment by eliminating or substantially reducing one or more pathways for exposure to a hazardous substance, that corrects a problem that may become substantially worse or cost substantially more to address if the remedial action is delayed, or that is needed to provide for completion of a site hazard assessment, remedial investigation/feasibility study, or design of a cleanup action plan. Any Party may propose an interim action under this Order. If the Parties are in agreement concerning the interim action, TransAlta shall prepare and submit to Ecology an Interim Action Work Plan, including a scope of work and schedule, by the date determined by Ecology. Ecology will provide public notice and opportunity to comment on the Interim Action Work Plan in accordance with WAC 173-340-600(16). TransAlta shall not conduct the interim action until Ecology approves the Interim Action Work Plan. Upon approval by Ecology, the Interim Action Work Plan becomes an integral and enforceable part of this Order, and TransAlta is required to conduct the interim action in accordance with the approved Interim Action Work Plan. If the Parties are not in agreement, Ecology reserves its authority to require interim action(s) under a separate order or other enforcement action under RCW 70A.305, or to undertake the interim action itself.

7.6 If Ecology determines that TransAlta has failed to make sufficient progress or failed to implement the remedial action, in whole or in part, Ecology may, after notice to TransAlta, perform any or all portions of the remedial action or at Ecology's discretion allow TransAlta opportunity to correct. In an emergency, Ecology is not required to provide notice to TransAlta, or an opportunity for dispute resolution. TransAlta shall reimburse Ecology for the costs of doing such work in accordance with Section 8.1

(Payment of Remedial Action Costs). Ecology reserves the right to enforce requirements of this Order under Section 10 (Enforcement).

7.7 Except where necessary to abate an emergency situation or where required by law, TransAlta shall not perform any remedial actions at the Site outside those remedial actions required by this Order to address the contamination that is the subject of this Order, unless Ecology concurs, in writing, with such additional remedial actions pursuant to Section 8.11 (Amendment of Order). In the event of an emergency, or where actions are taken as required by law, TransAlta must notify Ecology in writing of the event and remedial action(s) planned or taken as soon as practical but no later than within twenty-four (24) hours of the discovery of the event.

8. Terms and Conditions

8.1 Payment of Remedial Action Costs

TransAlta shall pay to Ecology costs incurred by Ecology pursuant to this Order and consistent with WAC 173-340-550(2). These costs shall include work performed by Ecology or its contractors for, or on, the Site under RCW 70A.305, including remedial actions and Order preparation, negotiation, oversight, and administration. These costs shall include work performed both prior to and subsequent to the issuance of this Order. Ecology's costs shall include costs of direct activities and support costs of direct activities as defined in WAC 173-340-550(2). For all Ecology costs incurred, TransAlta shall pay the required amount within thirty (30) days of receiving from Ecology an itemized statement of costs that includes a summary of costs incurred, an identification of involved staff, and the amount of time spent by involved staff members on the project. A general statement of work performed will be provided upon request. Itemized statements shall be prepared quarterly. Pursuant to WAC 173-340-550(4), failure to pay Ecology's costs within ninety (90) days of receipt of the itemized statement of costs will result in interest charges at the rate of twelve percent (12%) per annum, compounded monthly.

In addition to other available relief, pursuant to RCW 19.16.500, Ecology may utilize a collection agency and/or, pursuant to RCW 70A.305.060, file a lien against real property subject to the remedial actions to recover unreimbursed remedial action costs.

8.2 Designated Project Coordinators

The project coordinator for Ecology is:

Thomas Middleton, LHG
300 Desmond Drive, Lacey, WA 98503
360-999-9594
thomas.middleton@ecy.wa.gov

The project coordinator for TransAlta is:

Mickey Dreher
913 Big Hanaford Rd., Centralia, WA 98531-9101
360-330-8230
mickey_dreher@transalta.com

Each project coordinator shall be responsible for overseeing the implementation of this Order. Ecology's project coordinator will be Ecology's designated representative for the Site. To the maximum extent possible, communications between Ecology and TransAlta, and all documents, including reports, approvals, and other correspondence concerning the activities performed pursuant to the terms and conditions of this Order shall be directed through the project coordinators. The project coordinators may designate, in writing, working level staff contacts for all or portions of the implementation of the work to be performed required by this Order.

Any Party may change its respective project coordinator. Written notification shall be given to the other Party at least ten (10) calendar days prior to the change.

8.3 Performance

All geologic and hydrogeologic work performed pursuant to this Order shall be under the supervision and direction of a geologist or hydrogeologist licensed by the State of Washington or under the direct supervision of an engineer registered by the State of Washington, except as otherwise provided for by RCW 18.43 and 18.220.

All engineering work performed pursuant to this Order shall be under the direct supervision of a professional engineer registered by the State of Washington, except as otherwise provided for by RCW 18.43.130.

All construction work performed pursuant to this Order shall be under the direct supervision of a professional engineer or a qualified technician under the direct supervision of a professional engineer. The professional engineer must be registered by the State of Washington, except as otherwise provided for by RCW 18.43.130.

Any documents submitted containing geologic, hydrogeologic, or engineering work shall be under the seal of an appropriately licensed professional as required by RCW 18.43 and 18.220.

TransAlta shall notify Ecology in writing of the identity of any engineer(s) and geologist(s), contractor(s), subcontractor(s), and other key personnel to be used in carrying out the terms of this Order, in advance of their involvement at the Site.

8.4 Access

Ecology or any Ecology authorized representative, subject to proper qualification and conformance with TransAlta safety practices and policies applicable at the Site, shall have access to enter and freely move about all property at the Site that TransAlta either owns, controls, or has access rights to at all reasonable times for the purposes of, inter alia: inspecting records, operation logs, and contracts related to the work being performed pursuant to this Order; reviewing TransAlta's progress in carrying out the terms of this Order; conducting such tests or collecting such samples as Ecology may deem necessary; using a camera, sound recording, or other documentary type equipment to record work done pursuant to this Order; and verifying the data submitted to Ecology by TransAlta. Ecology or any Ecology authorized representative shall give reasonable notice before entering any Site property owned or controlled by TransAlta unless an emergency prevents such notice. All persons who access the Site pursuant to this section shall comply with any applicable health and safety plan(s). Ecology employees and their representatives shall not be required to sign any liability release or waiver as a condition of Site property access.

TransAlta shall make best efforts to secure access rights for those properties within the Site not owned or controlled by TransAlta where remedial activities or investigations will be performed pursuant to this Order. As used in this Section, "best efforts" means the efforts that a reasonable person in the position of TransAlta would use so as to achieve the goal in a timely manner, including the cost of employing professional assistance and the payment of reasonable sums of money to secure access and/or use restriction agreements, as required by this Section. If, within 30 days after the effective date of this Order, TransAlta is unable to accomplish what is required through "best efforts," they shall notify Ecology, and include a description of the steps taken to comply with the requirements. If Ecology deems it appropriate, it may assist TransAlta, or take independent action, in obtaining such access and/or use restrictions. Ecology reserves the right to seek payment from TransAlta for all costs, including cost of attorneys' time, incurred by Ecology in obtaining such access or agreements to restrict land, water, or other resource use.

8.5 Sampling, Data Submittal, and Availability

With respect to the implementation of this Order, TransAlta shall make the results of all sampling, laboratory reports, and/or test results generated by it or on its behalf available to Ecology. Pursuant to WAC 173-340-840(5), all sampling data shall be

submitted to Ecology in both printed and electronic formats in accordance with Section 7 (Work to be Performed), Ecology's Toxics Cleanup Program Policy 840 (Data Submittal Requirements), and/or any subsequent procedures specified by Ecology for data submittal.

If requested by Ecology, TransAlta shall allow Ecology and/or its authorized representative to take split or duplicate samples of any samples collected by TransAlta pursuant to implementation of this Order. TransAlta shall notify Ecology seven (7) days in advance of any sample collection or work activity at the Site. Ecology shall, upon request, allow TransAlta and/or its authorized representative to take split or duplicate samples of any samples collected by Ecology pursuant to the implementation of this Order, provided that doing so does not interfere with Ecology's sampling. Without limitation on Ecology's rights under Section 8.4 (Access), Ecology shall notify TransAlta prior to any sample collection activity unless an emergency prevents such notice.

In accordance with WAC 173-340-830(5)(a), all hazardous substance analyses shall be conducted by a laboratory accredited under WAC 173-50 for the specific analyses to be conducted, unless otherwise approved by Ecology.

8.6 Public Participation

RCW 70A.305.030(2)(a) requires that, at a minimum, this Order be subject to concurrent public notice. Ecology shall be responsible for providing this public notice and reserves the right to modify or withdraw any provisions of this Order should public comment disclose facts or considerations which indicate to Ecology that this Order is inadequate or improper in any respect.

Ecology shall maintain the responsibility for public participation at the Site. However, TransAlta shall cooperate with Ecology, and shall:

8.6.1 If agreed to by Ecology, develop appropriate mailing lists and prepare drafts of public notices and fact sheets at important stages of the remedial action, such as the submission of work plans, remedial investigation/feasibility study reports, cleanup action plans, and engineering design reports. As appropriate, Ecology will edit, finalize, and distribute such fact sheets and prepare and distribute public notices of Ecology's presentations and meetings.

8.6.2 Notify Ecology's project coordinator prior to the preparation of all press releases and fact sheets, and before meetings related to remedial action work to be performed at the Site with the interested public and/or local governments. Likewise, Ecology shall notify TransAlta prior to the issuance of all press releases and fact sheets related to the Site, and before meetings

related to the Site with the interested public and local governments. For all press releases, fact sheets, meetings, and other outreach efforts by TransAlta that do not receive prior Ecology approval, TransAlta shall clearly indicate to its audience that the press release, fact sheet, meeting, or other outreach effort was not sponsored or endorsed by Ecology.

8.6.3 When requested by Ecology, participate in public presentations on the progress of the remedial action at the Site. Participation may be through attendance at public meetings to assist in answering questions or as a presenter.

8.6.4 When requested by Ecology, arrange and maintain a repository to be located at:

Centralia Timberland Library
110 S. Silver Street, Centralia, WA 98531

At a minimum, copies of all public notices, fact sheets, and documents relating to public comment periods shall be promptly placed in these repositories. A copy of all documents related to this Site shall be maintained in the repository at Ecology's Southwest Regional Office in Lacey, Washington.

8.7 Access to Information

TransAlta shall provide to Ecology, upon request, copies of all records, reports, documents, and other information (including records, reports, documents, and other information in electronic form) (hereinafter referred to as "Records") within TransAlta's possession or control or that of their contractors or agents relating to activities at the Site or to the implementation of this Order, including, but not limited to, sampling, analysis, chain of custody records, manifests, trucking logs, receipts, reports, sample traffic routing, correspondence, or other documents or information regarding the work. TransAlta shall also make available to Ecology, for purposes of investigation, information gathering, or testimony, their employees, agents, or representatives with knowledge of relevant facts concerning the performance of the work.

Nothing in this Order is intended to waive any right TransAlta may have under applicable law to limit disclosure of Records protected by the attorney work-product privilege and/or the attorney-client privilege. If TransAlta withholds any requested Records based on an assertion of privilege, TransAlta shall provide Ecology with a privilege log specifying the Records withheld and the applicable privilege. No Site-related data collected pursuant to this Order shall be considered privileged, including: (1) any data regarding the Site, including, but not limited to, all sampling, analytical,

monitoring, hydrogeologic, scientific, chemical, radiological, biological, or engineering data, or the portion of any other record that evidences conditions at or around the Site; or (2) the portion of any Record that Respondents are required to create or generate pursuant to this Order.

Notwithstanding any provision of this Order, Ecology retains all of its information gathering and inspection authorities and rights, including enforcement actions related thereto, under any other applicable statutes or regulations.

8.8 Retention of Records

During the pendency of this Order, and for ten (10) years from the date of completion of the work performed pursuant to this Order, TransAlta shall preserve all records, reports, documents, and underlying data in its possession relevant to the implementation of this Order and shall insert a similar record retention requirement into all contracts with project contractors and subcontractors.

8.9 Resolution of Disputes

8.9.1 In the event that TransAlta elects to invoke dispute resolution TransAlta must utilize the procedure set forth below.

8.9.1.1 Upon the triggering event (receipt of Ecology's project coordinator's written decision or an itemized billing statement), TransAlta has fourteen (14) calendar days within which to notify Ecology's project coordinator in writing of its dispute (Informal Dispute Notice).

8.9.1.2 The Parties' project coordinators shall then confer in an effort to resolve the dispute informally. The Parties shall informally confer for up to fourteen (14) calendar days from receipt of the Informal Dispute Notice. If the project coordinators cannot resolve the dispute within those fourteen (14) calendar days, then within seven (7) calendar days Ecology's project coordinator shall issue a written decision (Informal Dispute Decision) stating: the nature of the dispute; the TransAlta position with regards to the dispute; Ecology's position with regards to the dispute; and the extent of resolution reached by informal discussion.

8.9.1.3 TransAlta may then request regional management review of the dispute. TransAlta must submit this request (Formal Dispute Notice) in writing to the Southwest Region Toxics Cleanup Section

Manager within seven (7) calendar days of receipt of Ecology's Informal Dispute Decision. The Formal Dispute Notice shall include a written statement of dispute setting forth: the nature of the dispute; the TransAlta position with respect to the dispute; and the information relied upon to support its position.

8.9.1.4 The Section Manager shall conduct a review of the dispute and shall issue a written decision regarding the dispute (Decision on Dispute) within thirty (30) calendar days of receipt of the Formal Dispute Notice. The Decision on Dispute shall be Ecology's final decision on the disputed matter.

8.9.2 The Parties agree to only utilize the dispute resolution process in good faith and agree to expedite, to the extent possible, the dispute resolution process whenever it is used.

8.9.3 Implementation of these dispute resolution procedures shall not provide a basis for delay of any activities required in this Order, unless Ecology agrees in writing to a schedule extension.

8.9.4 In case of a dispute, failure to either proceed with the work required by this Order or timely invoke dispute resolution may result in Ecology's determination that insufficient progress is being made in preparation of a deliverable, and may result in Ecology undertaking the work under Section 7 (Work to be Performed) or initiating enforcement under Section 10 (Enforcement).

8.10 Extension of Schedule

8.10.1 TransAlta's requests for an extension of schedule shall be granted only when a request for an extension is submitted in a timely fashion, generally at least thirty (30) days prior to expiration of the deadline for which the extension is

requested, and good cause exists for granting the extension. All extensions shall be requested in writing. The request shall specify:

8.10.1.1 The deadline that is sought to be extended.

8.10.1.2 The length of the extension sought.

8.10.1.3 The reason(s) for the extension.

8.10.1.4 Any related deadline or schedule that would be affected if the extension were granted.

8.10.2 The burden shall be on TransAlta to demonstrate to the satisfaction of Ecology that the request for such extension has been submitted in a timely fashion and that good cause exists for granting the extension. Good cause may include, but may not be limited to:

8.10.2.1 Circumstances beyond the reasonable control and despite the due diligence of TransAlta including delays caused by unrelated third parties or Ecology, such as (but not limited to) delays by Ecology in reviewing, approving, or modifying documents submitted by TransAlta.

8.10.2.2 A shelter in place or work stoppage mandated by state or local government order due to public health and safety emergencies.

8.10.2.3 Acts of God, including fire, flood, blizzard, extreme temperatures, storm, or other unavoidable casualty.

8.10.2.4 Endangerment as described in Section 8.12 (Endangerment).

However, neither increased costs of performance of the terms of this Order nor changed economic circumstances shall be considered circumstances beyond the reasonable control of TransAlta.

8.10.3 Ecology shall act upon any written request from TransAlta for extension in a timely fashion. Ecology shall give TransAlta written notification of any extensions granted pursuant to this Order. A requested extension shall not be effective until approved by Ecology. Unless the extension is a substantial

change, it shall not be necessary to amend this Order pursuant to Section 8.11 (Amendment of Order) when a schedule extension is granted.

8.10.4 At TransAlta's request, an extension shall only be granted for such period of time as Ecology determines is reasonable under the circumstances. Ecology may grant schedule extensions exceeding ninety (90) days only as a result of one of the following:

8.10.4.1 Delays in the issuance of a necessary permit which was applied for in a timely manner.

8.10.4.2 Other circumstances deemed exceptional or extraordinary by Ecology.

8.10.4.3 Endangerment as described in Section 8.12 (Endangerment).

8.11 Amendment of Order

The project coordinators may verbally agree to minor changes to the work to be performed without formally amending this Order. Minor changes will be documented in writing by Ecology within seven (7) days of verbal agreement.

Except as provided in Section 8.13 (Reservation of Rights), substantial changes to the work to be performed shall require formal amendment of this Order. This Order may only be formally amended by the written consent of both Ecology and TransAlta. Ecology will provide its written consent to a formal amendment only after public notice and opportunity to comment on the formal amendment.

When requesting a change to the Order, TransAlta shall submit a written request to Ecology for approval. Ecology shall indicate its approval or disapproval in writing and in a timely manner after the written request is received. If Ecology determines that the change is substantial, then the Order must be formally amended. Reasons for the disapproval of a proposed change to this Order shall be stated in writing. If Ecology does not agree to a proposed change, the disagreement may be addressed through the dispute resolution procedures described in Section 8.9 (Resolution of Disputes).

8.12 Endangerment

In the event Ecology determines that any activity being performed at the Site under this Order is creating or has the potential to create a danger to human health or the environment on or surrounding the Site, Ecology may direct TransAlta to cease such activities for such period of time as it deems necessary to abate the danger. TransAlta shall immediately comply with such direction.

In the event TransAlta determines that any activity being performed at the Site under this Order is creating or has the potential to create a danger to human health or the environment, TransAlta may cease such activities. TransAlta shall notify Ecology's project coordinator as soon as possible, but no later than twenty-four (24) hours after making such determination or ceasing such activities. Upon Ecology's direction, TransAlta shall provide Ecology with documentation of the basis for the determination or cessation of such activities. If Ecology disagrees with TransAlta's cessation of activities, it may direct TransAlta to resume such activities.

If Ecology concurs with or orders a work stoppage pursuant to this section, TransAlta's obligations with respect to the ceased activities shall be suspended until Ecology determines the danger is abated, and the time for performance of such activities, as well as the time for any other work dependent upon such activities, shall be extended in accordance with Section 8.10 (Extension of Schedule) for such period of time as Ecology determines is reasonable under the circumstances.

Nothing in this Order shall limit the authority of Ecology, its employees, agents, or contractors to take or require appropriate action in the event of an emergency.

8.13 Reservation of Rights

This Order is not a settlement under RCW 70A.305. Ecology's signature on this Order in no way constitutes a covenant not to sue or a compromise of any of Ecology's rights or authority. Ecology will not, however, bring an action against TransAlta to recover remedial action costs paid to and received by Ecology under this Order. In addition, Ecology will not take additional enforcement actions against TransAlta regarding remedial actions required by this Order, provided TransAlta complies with this Order.

Ecology nevertheless reserves its rights under RCW 70A.305, including the right to require additional or different remedial actions at the Site should it deem such actions necessary to protect human health or the environment, and to issue orders requiring such remedial actions. Ecology also reserves all rights regarding the injury to, destruction of, or loss of natural resources resulting from the release or threatened release of hazardous substances at the Site.

By entering into this Order, TransAlta does not admit to any liability for the Site. Although TransAlta is committing to conducting the work required by this Order under the terms of this Order, TransAlta expressly reserves all rights available under law, including but not limited to the right to seek cost recovery or contribution against third parties, and the right to assert any defenses to liability in the event of enforcement.

8.14 Transfer of Interest in Property

No voluntary conveyance or relinquishment of title, easement, leasehold, or other interest in any portion of the Site shall be consummated by TransAlta without provision for continued implementation of all requirements of this Order and implementation of any remedial actions found to be necessary as a result of this Order.

Prior to TransAlta's transfer of any interest in all or any portion of the Site, and during the effective period of this Order, TransAlta shall provide a copy of this Order to any prospective purchaser, lessee, transferee, assignee, or other successor in said interest; and, at least thirty (30) days prior to any transfer, TransAlta shall notify Ecology of said transfer. Upon transfer of any interest, TransAlta shall notify all transferees of the restrictions on the activities and uses of the property under this Order and incorporate any such use restrictions into the transfer documents.

8.15 Compliance with Applicable Laws

8.15.1 **Applicable laws.** All actions carried out by TransAlta pursuant to this Order shall be done in accordance with all applicable federal, state, and local requirements, including requirements to obtain necessary permits or approvals, except as provided in RCW 70A.305.090. At this time, TransAlta is obligated to fulfil the requirements of RCW Chapters 80.80 and 80.82 and that entry into and compliance with this order is done in satisfaction of those laws and the 2011 MOA. TransAlta and Ecology will also comply with the requirements of any additional agreements executed between TransAlta and the State of Washington that affect the Site. TransAlta has a continuing obligation to identify additional applicable federal, state, and local requirements which apply to actions carried out pursuant to this Order, and to comply with those requirements. As additional federal, state, and local requirements are identified by Ecology or TransAlta, Ecology will document in writing if they are applicable to actions carried out pursuant to this Order, and TransAlta must implement those requirements.

8.15.2 **Relevant and Appropriate Requirements.** All actions carried out by TransAlta pursuant to this Order shall be done in accordance with relevant and appropriate requirements identified by Ecology. At this time, no relevant and appropriate requirements have been identified as being applicable to the actions required by this Order. If additional relevant and appropriate requirements are identified by Ecology or TransAlta, Ecology will document in

writing if they are applicable to actions carried out pursuant to this Order and TransAlta must implement those requirements.

8.15.3 Pursuant to RCW 70A.305.090(1), TransAlta may be exempt from the procedural requirements of RCW 70A.15, 70A.205, 70A.300, 77.55, 90.48, and 90.58 and of any laws requiring or authorizing local government permits or approvals. However, TransAlta shall comply with the substantive requirements of such permits or approvals. For permits and approvals covered under RCW 70A.305.090(1) that have been issued by local government, the Parties agree that Ecology has the non-exclusive ability under this Order to enforce those local government permits and/or approvals. At this time, no state or local permits or approvals have been identified as being applicable but procedurally exempt under this section.

8.15.4 TransAlta has a continuing obligation to determine whether additional permits or approvals addressed in RCW 70A.305.090(1) would otherwise be required for the remedial action under this Order. In the event either Ecology or TransAlta determines that additional permits or approvals addressed in RCW 70A.305.090(1) would otherwise be required for the remedial action under this Order, it shall promptly notify the other Party of its determination. Ecology shall determine whether Ecology or TransAlta shall be responsible to contact the appropriate state and/or local agencies. If Ecology so requires, TransAlta shall promptly consult with the appropriate state and/or local agencies and provide Ecology with written documentation from those agencies of the substantive requirements those agencies believe are applicable to the remedial action. Ecology shall make the final determination on the additional substantive requirements that must be met by TransAlta and on how TransAlta must meet those requirements. Ecology shall inform TransAlta in writing of these requirements. Once established by Ecology, the additional requirements shall be enforceable requirements of this Order. TransAlta shall not begin or continue the remedial action potentially subject to the additional requirements until Ecology makes its final determination.

Pursuant to RCW 70A.305.090(2), in the event Ecology determines that the exemption from complying with the procedural requirements of the laws referenced in RCW 70A.305.090(1) would result in the loss of approval from a federal agency that is necessary for the state to administer any federal law, the exemption shall not apply and TransAlta shall comply with both the procedural and substantive requirements of the laws referenced in RCW 70A.305.090(1), including any requirements to obtain permits or approvals.

8.16 Periodic Review

So long as remedial action continues at the Site, the Parties agree to review the progress of remedial action at the Site, and to review the data accumulated as a result of monitoring the Site as often as is necessary and appropriate under the circumstances. Unless otherwise agreed to by Ecology, at least every five (5) years after the initiation of cleanup action at the Site the Parties shall confer regarding the status of the Site and the need, if any, for further remedial action at the Site. At least ninety (90) days prior to each periodic review, TransAlta shall submit a report to Ecology that documents whether human health and the environment are being protected based on the factors set forth in WAC 173-340-420(4). Ecology reserves the right to require further remedial action at the Site under appropriate circumstances. This provision shall remain in effect for the duration of this Order.

8.17 Indemnification

TransAlta agrees to indemnify and save and hold the State of Washington, its employees, and agents harmless from any and all claims or causes of action (1) for death or injuries to persons, or (2) for loss or damage to property, to the extent arising from or on account of acts or omissions of TransAlta, its officers, employees, agents, or contractors in entering into and implementing this Order. However, TransAlta shall not indemnify the State of Washington nor save nor hold its employees and agents harmless from any claims or causes of action to the extent arising out of the negligent acts or omissions of the State of Washington, or the employees or agents of the State, in entering into or implementing this Order.

9. Satisfaction of Order

The provisions of this Order shall be deemed satisfied upon TransAlta's receipt of written notification from Ecology that TransAlta has completed the remedial activity required by this Order, including implementation of the final cleanup action plan, as amended by any modifications, and that TransAlta has complied with all other provisions of this Agreed Order.

10. Enforcement

Pursuant to RCW 70A.305.050, this Order may be enforced as follows:

10.1 The Attorney General may bring an action to enforce this Order in a state or federal court.

10.2 The Attorney General may seek, by filing an action, if necessary, to recover amounts spent by Ecology for investigative and remedial actions and orders related to the Site.

10.3 A liable party who refuses, without sufficient cause, to comply with any term of this Order will be liable for:

10.3.1 Up to three (3) times the amount of any costs incurred by the State of Washington as a result of its refusal to comply.

10.3.2 Civil penalties of up to twenty-five thousand dollars ($25,000) per day for each day it refuses to comply.

10.4 This Order is not appealable to the Washington Pollution Control Hearings Board. This Order may be reviewed only as provided under RCW 70A.305.070.

Effective date of this Order: December 29, 2025

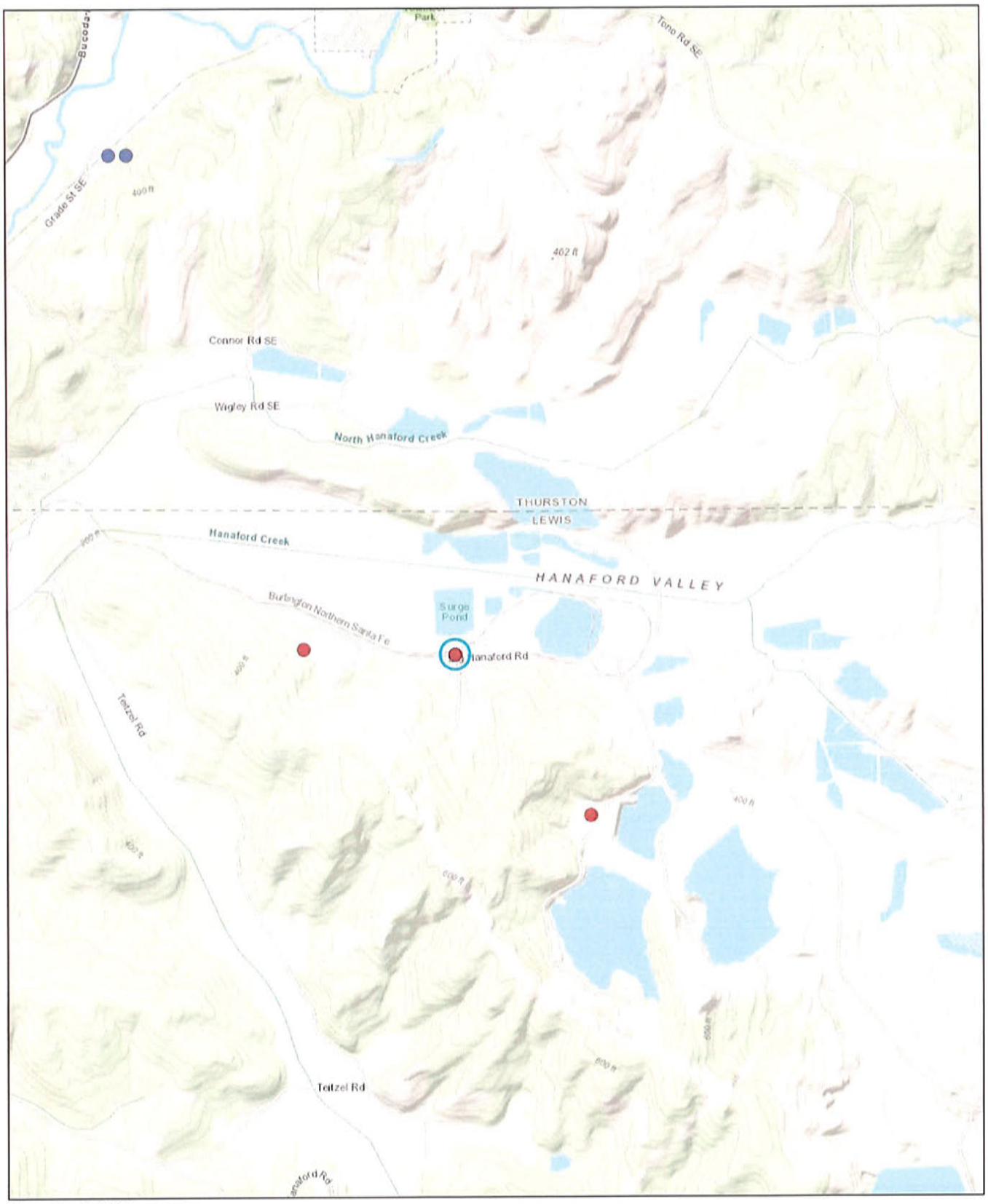
TransAlta

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State of Washington
Department of Ecology

Marian Abbett, PE
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Toxics Cleanup Program
Southwest Region Office
360-489-4569

Exhibit A - Location Diagram



November 6, 2025

TCP Cleanupsites 2

Cleanup Status

- Awaiting Cleanup
- Complete

1:36,112

0 0.23 0.45 0.9 mi

0 0.35 0.7 1.4 km

N

Sources: Esri, HERE, Garmin, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), (c) OpenStreetMap contributors, and the GIS User Community, WA Dept. of Ecology

Exhibit B — TransAlta scope of work and schedule

Scope of work

Purpose

The work under this Agreed Order (AO) involves conducting a Remedial Investigation (RI) and Feasibility Study (FS), conducting interim actions if required or agreed to by Ecology, preparing a preliminary Draft Cleanup Action Plan (DCAP) to select a cleanup alternative, and implementing the CAP as approved by Ecology. The purpose of the RI, FS, and preliminary DCAP for the Site is to provide sufficient data, analysis, and evaluations to enable Ecology to select and approve a cleanup alternative for the Site.

TransAlta shall coordinate with Ecology throughout the development of the RI/FS and preliminary DCAP and shall keep Ecology informed of changes to any Work Plan or other project plans, and of any issues or problems as they develop.

The Scope of Work (SOW) is divided into eight major tasks as follows:

Task 1. Supplemental RI Work Plan
Task 2. Supplemental Remedial Investigation
Task 3. Interim Action(s) (if required)
Task 4. Feasibility Study
Task 5. SEPA Compliance
Task 6. Public Participation
Task 7. DCAP
Task 8. Implementation of the CAP

Task 1. Supplemental RI work plan

TransAlta shall prepare a Supplemental Remedial Investigation Work Plan (Work Plan). The Work Plan shall address the deficiencies, noted by Ecology, in our comments on the submitted RI report including provisions for a survey of potential deposition of semi-volatile organic compounds, carcinogenic polycyclic aromatic hydrocarbons, dioxins/furans, and metals including mercury, in the areas surrounding the coal plant property.

The Work Plan shall, as needed, describe general facility information; site history and conditions; including previous operations; past field investigations, including any data collection and analysis of soils, air, groundwater, surface water, and sediments; a conceptual site model showing contaminants, migration pathways in all environmental media, and potential receptors; geology and groundwater system characteristics; past, current, and future land use; identification of natural resources and ecological receptors; hazardous substances and their sources, etc., in compliance with WAC 173-340-350 and WAC 173-204-550.

The Work Plan will also identify specific data collection procedures in a Sampling and Analysis Plan (SAP) and Quality Assurance Project Plan (QAPP) as part of the Work Plan in compliance with WAC 173-340-820 and WAC 173-204-600 for defining the nature and extent of contamination. TransAlta will also submit a copy of the Health and Safety Plan (HASP) for the project.

The SAP identifies the proposed number and location of all environmental samples and methods, including soil borings, groundwater monitoring wells, soil, groundwater, stormwater, seep, catch basin and sediment samples, approximate depths, and includes a quality assurance project plan. The SAP will describe the sampling objectives, the rationale for the sampling approach (based upon the identified data gaps), and plans for data use, and shall provide a detailed description of sampling tasks. The SAP shall describe specifications for sample identifiers; sampling equipment; the type, number, and location of samples to be collected; the analyses to be performed; descriptions of sampling equipment and methods to be used; sample documentation; sample containers, collection and handling; data and records management; and schedule.

The Quality Assurance Project Plan (QAPP) will be prepared in accordance with the Guidance for Preparation of Quality Assurance Project Plans, EPA Region 10, Quality Data Management Program, QA/R-5 and requirements of the EPA Contract Laboratory Program. The QAPP will also follow Ecology's Guidelines for Preparing Quality Assurance Project Plans for Environmental Studies (July 2004) and Sediment Sampling and Analysis Plan Appendix (February 2008). Laboratories must meet the accreditation standards established in WAC 173-50. Data quality objectives will reflect the criteria or threshold values used for the source control evaluation.

The SAP, including the QAPP, will be submitted to Ecology for review and approval. As with all environmental work at the site, work may not begin without written approval from Ecology. The plan shall provide seven (7) days notice to Ecology prior to beginning sampling. Ecology may obtain split samples.

TransAlta or their contractors shall submit all new sampling data generated under this SAP and any other recently collected data to Ecology for entry into the Environmental Information Management System (EIM) in accordance with WAC 173-340-840(5) and Ecology's Toxics Cleanup Program Policy 840: Data Submittal Requirements. Only validated data will be entered into the EIM database within 30 days of submittal.

TransAlta will provide Ecology with an Agency Review Draft Work Plan. Once Ecology reviews and approves the Work Plan, it will be considered the Final Work Plan. The Work Plan shall not be implemented until approved by Ecology. Once approved by Ecology, TransAlta will implement the Final Work Plan according to the schedule contained in this Exhibit.

TransAlta shall prepare two (2) copies of the Agency Review Draft RI Work Plan and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology for review and comment. After incorporating Ecology's comments on the Agency Review Draft Work Plan and after Ecology approval, TransAlta shall prepare three (3) copies of the Final Work Plan and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology.

Task 2. Supplemental Remedial Investigation

TransAlta shall conduct a Supplemental RI that meets the requirements of WAC 173-340-350 and WAC 173-204-550 according to the Work Plan as approved by Ecology. The RI will determine the nature and extent of contamination exceeding preliminary Model Toxics Control Act (MTCA) cleanup levels, preliminary Sediment Management Standards (SMS) cleanup standards, and other regulatory requirements. The RI must provide sufficient data and information to define the nature and extent of contamination.

Field sampling and analysis will be completed in general accordance with the SAP and QAPP. Deviation(s) from the approved SAP and QAPP must be communicated to Ecology immediately and documented as required by Ecology.

TransAlta shall provide interim data reports and updates to Ecology as new site data and information become available. Laboratory analysis data shall also be provided in electronic format when it has been validated. Raw laboratory data will be provided to Ecology upon request.

Prior to submittal of the Agency Review Draft RI Report, a Key Project Meeting will be held. During the Remedial Investigation Pre-Report Check-In, Ecology and TransAlta will review available data and an updated conceptual site model and discuss the content and organization of the Draft RI Report.

TransAlta shall compile the results of the Site investigation into an Agency Review Draft RI Report. TransAlta shall prepare two (2) copies of the Agency Review Draft RI Report and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology for review and comment.

After incorporating Ecology's comments on the Agency Review Draft RI Report, TransAlta shall prepare three (3) copies of a Public Review Draft RI Report and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology for distribution and public comment. Electronic survey data for monitoring locations, electronic lab data, and GIS maps of contaminant distribution shall also be provided for both the Agency Review Draft RI Report and Public Review Draft RI Reports either in the report or as attachments. The RI Report will not be considered Final until after a public review and comment period.

If the data collected during this investigation is insufficient to define the nature and extent of contamination, and/or to select a cleanup action plan an additional phase of investigation shall be conducted to define the extent of contamination.

Task 3. Interim Actions (if required)

Remedial actions implemented prior to completion of the RI/FS, including those that:

- are technically necessary to reduce a threat to human health or the environment by eliminating or substantially reducing one or more pathways for exposure to a hazardous substance;
- correct a problem that may become substantially worse or cost substantially more to address if the remedial action is delayed; or
- are needed to provide for completion of the remedial investigation/feasibility study or design of the cleanup action

will be considered interim actions, will be implemented in accordance with WAC 173-340-430 and the AO, and will be designed in a manner that will not foreclose reasonable alternatives for any final cleanup action that may be required.

As detailed in the AO, if required by Ecology, or if proposed by TransAlta and approved by Ecology, TransAlta will implement an interim action. Based upon information in the Agency Review Draft RI Report, interim action(s) may be needed to expedite control of releases to sediments or other environmental media pursuant to WAC 173-340-430.

The scope of the interim actions may include, but not be limited to, typical source control or containment elements such as:

- Soil or sediment removal
- Groundwater remediation
- Repair, slip lining, replacement, or closure of stormwater conveyances or other structures such as conduit, vaults, catch basins, etc.
- Removal of underground storage tanks and pipes
- Removal of old drain fields or former surface impoundments
- Proper abandonment of old wells
- Removal of contaminated building or other structural material
- Construction of a treatment facility
- Shoreline stabilization such as bulkhead repair, erosion or seepage control, and grading or clearing.

If an interim action is to be performed, TransAlta will prepare and submit for Ecology approval an Agency Review Draft Interim Action Work Plan (IAWP) with detail commensurate with the work to be performed. The Agency Review Draft IAWP shall include, as appropriate:

- Description of the interim action including its purpose, general requirements, and relationship to the (final) cleanup action (to the extent known);
- Summary of relevant RI/FS information, including at a minimum existing site conditions and alternative interim actions considered;
- Information regarding design and construction requirements, including a proposed schedule and personnel roles and responsibilities;
- Compliance Monitoring Plan;
- SAP/QAPP;
- Permits required.

TransAlta will also submit a copy of the Health and Safety Plan for the project. TransAlta will be responsible for complying with the State Environmental Policy Act (SEPA) Rules including preparing and submitting an environmental checklist for the interim action, and will assist Ecology with presentations at any additional meetings or hearings that might be necessary for SEPA compliance or as part of the Public Participation Plan.

TransAlta shall prepare two (2) copies of the Agency Review Draft Interim Action Work Plan and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology for review. TransAlta shall incorporate Ecology's comments and then prepare two (2) copies of the Public Review Draft Interim Action Work Plan and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology. After a public notice and comment period for the Public Review Draft IAWP (and SEPA determination), Ecology will approve the IAWP (if appropriate) and the document will be considered Final. TransAlta shall prepare three (3) copies of the Final Interim Action Work Plan submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats. Once approved by Ecology, TransAlta will implement the interim action according with the approved schedule.

Upon successful completion of the work, an Agency Review Draft Interim Action Report will be prepared as a separate deliverable. TransAlta shall prepare two (2) copies of the Agency Review Draft Interim Action Report and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology for review and approval. After incorporating Ecology's comments on the Agency Review Draft Interim Action Report and after Ecology approval, TransAlta shall prepare three (3) copies of the Final Interim Action Report and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology.

Task 4. Feasibility study

TransAlta shall use the information obtained in the RI to prepare an Agency Review Draft Feasibility Study (FS) that meets the applicable requirements of WAC 173-340-351 according to the Schedule in this exhibit. The Agency Review Draft FS will evaluate remedial alternatives for site cleanup, consistent with MTCA and SMS requirements to ensure protection of human health and the environment by eliminating, reducing, or otherwise controlling risk posed through each exposure pathway and migration route.

Prior to beginning the FS, a Key Project Meeting will be held to review ARARs, potential remedial alternatives and establish points of compliance.

The Agency Review Draft FS must include a detailed analysis of each remedial alternative according to the applicable requirements of WAC 173-340-351 and 173-204-550. The remedial alternatives will be evaluated for compliance with the applicable requirements of WAC 173-340-360 and 173-204-570.

The remedial alternative that is judged to best satisfy the evaluation criteria will be identified. Justification for the selection will be provided, and the recommended remedial alternative further developed, in the FS Report.

TransAlta shall prepare two (2) copies of the Agency Review Draft FS and submit them, including one electronic copy in Word (.doc) and Adobe (.pdf) formats, to Ecology for review. After addressing Ecology's comments on the Agency Review Draft FS, TransAlta shall prepare three (3) copies of the Public Review Draft FS and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology for distribution and public comment. The FS will not be considered Final until after a public review and comment period.

Task 5. SEPA compliance

TransAlta shall be responsible for complying with the State Environmental Policy Act (SEPA) Rules including preparing and submitting an environmental checklist. If the result of the threshold determination is a determination of significance (DS), TransAlta shall be responsible for the preparation of Draft and final environmental impact statements. TransAlta shall assist Ecology with coordinating SEPA public involvement requirements with MTCA public involvement requirements whenever possible, such that public comment periods and meetings or hearings can be held concurrently.

Task 6. Public participation

TransAlta shall support Ecology in presenting the Public Review Draft RI Report and the Public Review Draft FS Reports and SEPA evaluations at one public meeting or hearing. TransAlta will assist Ecology with presentations at any additional meetings or hearings that might be necessary for SEPA compliance or as part of the Public Participation Plan.

After the public comment periods are completed, TransAlta shall prepare a Agency Review Draft Responsiveness Summary that addresses public comments. TransAlta shall prepare two (2) copies of the Agency Review Draft Responsiveness Summary and submit them to Ecology for review and approval, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology for distribution and public comment.

After addressing Ecology's comments and after Ecology approval, TransAlta shall prepare five (5) copies of the Final Responsiveness Summary and submit them to Ecology for distribution, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats.

Task 7. Preliminary draft Cleanup Action Plan

Upon Ecology approval of the Public Review Draft Remedial Investigation Report and Public Review Draft Feasibility Study, a Key Project Meeting will be held regarding the Cleanup Action Plan. The Cleanup Action Plan Meeting will be used to review plans for developing the Agency Review preliminary Draft Cleanup Action Plan (DCAP).

TransAlta shall prepare an Agency Review preliminary DCAP in accordance with WAC 173-340-380 that provides a proposed remedial action to address the contamination present on the Site. The preliminary DCAP shall include a general description of the proposed remedial actions, cleanup standards developed from the RI/FS and rationale regarding their selection, a schedule for implementation, description of any institutional controls proposed, and a summary of applicable local, state, and federal laws pertinent to the proposed cleanup actions.

TransAlta will submit an Agency Review preliminary DCAP for Ecology's review and approval. The Agency Review preliminary DCAP will include, but not be limited to, the information listed under WAC 173-340-380. TransAlta shall prepare two (2) copies of the Agency Review preliminary DCAP and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology for review and approval.

After receiving Ecology's comments on the Agency Review preliminary DCAP, if any, TransAlta shall revise the preliminary DCAP to address Ecology's comments and submit five (5) copies of the Public Review DCAP including one electronic copy each in Word (.doc) and Adobe (.pdf) formats.

Task 8. Implementation of CAP

TransAlta agrees, as part of the AO, that they will implement the final CAP following both public review and Ecology approval.

Schedule of deliverables

The schedule for deliverables described in the Agreed Order and the Scope of Work is presented below. If the date for submission of any item or notification required by this

Schedule of Deliverables occurs on a weekend, state or federal holiday, the date for submission of that item or notification is extended to the next business day following the weekend or holiday. Where a deliverable due date is triggered by Ecology notification, comments or approval, the starting date for the period shown is the date TransAlta received such notification, comments or approval by certified mail, return receipt requested, unless otherwise noted below. Where triggered by Ecology receipt of a deliverable, the starting date for the period shown is the date Ecology receives the deliverable by certified mail, return receipt requested, or the date of Ecology signature on a hand-delivery form.

RI/FS Deliverables	Completion Times
Agency Review Draft Supplemental RI Work Plan	60 calendar days following effective date of the Agreed Order
Completion of RI Field Work	12 months following Ecology approval of the Final SAP, QAPP and HSP
Agency Review Draft RI Report	90 days following receipt of validated laboratory data package
Public Review Draft RI Report	45 calendar days following receipt of Ecology's comments on Agency Review Draft RI Report
Agency Review Draft FS	90 days following Ecology approval of Public Review Draft RI Report
Public Review Draft FS	45 calendar days following receipt of Ecology's comments on the Agency Review draft FS
Agency Review preliminary Draft Cleanup Action Plan (DCAP)	90 calendar days following Ecology approval of the Public Review Draft FS.
Implementation of Final CAP	Following public comment on Ecology's DCAP, Ecology will finalize the CAP. Final CAP will detail schedule for design and construction of remedy.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-114:
Wash. Exec. Order 09-05 (May 2009)

CHRISTINE O. GREGOIRE
Governor



STATE OF WASHINGTON

OFFICE OF THE GOVERNOR

P.O. Box 40002 · Olympia, Washington 98504-0002 · (360) 753-6780 · www.governor.wa.gov

EXECUTIVE ORDER 09-05

WASHINGTON'S LEADERSHIP ON CLIMATE CHANGE

WHEREAS, Washington is particularly vulnerable to the impacts of climate change, and without additional action to reduce carbon emissions, the severity of the impacts will negatively affect nearly every part of Washington's economy and environment; and

WHEREAS, Washington is already experiencing the effects of a changing climate and needs to address current and future projected impacts; and

WHEREAS, greenhouse gases are air contaminants within the meaning of the state's Clean Air Act and pose a serious threat to the health and welfare of Washington's citizens and the quality of the environment; and

WHEREAS, energy independence and security are vitally important, and maintaining Washington's leadership position in the development of clean energy and green jobs is critical to our economic and energy future; and

WHEREAS, RCW 70.235.020 establishes greenhouse gas emission reduction limits for Washington State, and RCW 47.01.440 establishes vehicle miles traveled benchmarks for Washington State; and

WHEREAS, alternative vehicle technologies can provide economic development opportunities and reduce Washington's transportation sector greenhouse gas emissions, criteria pollutants, and toxic air contaminants; and

WHEREAS, Washington's extensive forest resources play an important role in capturing and storing carbon dioxide; and

WHEREAS, it is critical to Washington's economic future that greenhouse gas reduction strategies be designed and implemented in a manner that minimizes cost impacts to Washington citizens and businesses; and

WHEREAS, President Obama and the United States Congress are actively working to establish a strong federal response to climate change, and regional and state level greenhouse gas reduction programs will inform and complement a federal program; and

WHEREAS, effective and immediate action to reduce greenhouse gas emissions – preferably at the federal level but at the regional or state level as necessary – is essential to the future well being of all Washingtonians.

NOW, THEREFORE, I, Christine O. Gregoire, Governor of the state of Washington by virtue of the power vested in me by the Constitution and statutes of the state of Washington do, effective immediately, hereby order and direct:

1. The Director of the Department of Ecology to:

    (a) Continue to participate in the Western Climate Initiative to develop a regional greenhouse gas emission reduction program and to work with the federal Administration, Washington's congressional delegation and appropriate committees to help design a national greenhouse gas emission reduction program that reflects Washington State priorities. Those priorities include: protecting small businesses and families, particularly those with low incomes, in the transition to a clean energy future; investing in clean energy development, demonstration and deployment; ensuring appropriate credit for early emission reductions; providing a level playing field that allows Washington's businesses to fairly compete; recognizing Washington's unique electricity-generating portfolio, its forest industry and other important resources; and ensuring the program spurs the creation of green jobs.

    (b) By December 1, 2009, provide to each facility that the Department of Ecology believes is responsible for the emission of 25,000 metric tons or more of carbon dioxide equivalent each year in Washington with (1) the Department's best estimate of each facility's baseline greenhouse gas emissions; and (2) each facility's proportionate share greenhouse gas emission reduction necessary to achieve the state's 2020 emission reduction in RCW 70.135.020; and (3) a request to each facility, or groups of facilities representing a sector of Washington's economy, for any recommended strategies or actions they believe would achieve the needed reductions. By October 1, 2010, the Department of Ecology shall develop emission reduction strategies and actions, including complementary policies, to achieve the state's 2020 emissions reduction targets.

    (c) In consultation with business and other interested stakeholders, develop emission benchmarks, by industry sector, for facilities the Department of Ecology believes will be covered by a federal or regional cap and trade program. The Department of Ecology shall support the use of these emission benchmarks in any federal or regional cap and trade program as an appropriate basis for the distribution of emission allowances, and as a means to recognize and reward those businesses that have invested in achieving emission reductions. These benchmarks shall be based on industry best practices, reflecting emission levels from highly efficient, lower emitting facilities in each industry sector. The benchmarks shall be developed to allow their application as state-based emissions standards, should they be needed to complement the federal program, or in the absence of a federal program.

Recommendations on industry benchmarks, and the appropriate use of these benchmarks in achieving the state emission reduction targets, shall be submitted to the Governor by July 1, 2011;

(d) Work with the existing coal-fired plant within Washington that burns over one million tons of coal per year, TransAlta Centralia Generation LLC, to establish an agreed order that will apply the greenhouse gas emissions performance standards in RCW 80.80.040(1) to the facility by no later than December 31, 2025. The agreed order shall include a schedule of major decision making and resource investment milestones;

(e) In consultation with the Department of Natural Resources and the forest carbon sector working group, develop by September 1, 2010, recommendations for forestry offset protocols as well as other financial incentives for forestry and forest products. The starting point for this work should be the 2008 forest sector working group report; and

(f) In consultation with the Departments of Commerce and Transportation, assess whether the California low-carbon fuel standards; standards developed or proposed in other states, provinces or for the nation; or modified standards or alternative requirements to reduce carbon in transportation fuels would best meet Washington's greenhouse gas emissions reduction targets. By July 1, 2010, provide to the Governor a recommendation regarding which standards or requirements should be adopted for Washington, either by rule or legislation.

2. The Secretary of the Department of Transportation to:

(a) In consultation with the Departments of Ecology and Commerce, and in collaboration with local governments, business, and environmental representatives, estimate current and future state-wide levels of vehicle miles traveled, evaluate potential changes to the vehicle miles traveled benchmarks established in RCW 47.01.440 as appropriate to address low- or no-emission vehicles, and develop additional strategies to reduce emissions from the transportation sector. Findings and recommendations from this work shall be reported to the Governor by December 31, 2010; and,

(b) Work with the Puget Sound Regional Council, Spokane Regional Transportation Council, Southwest Washington Regional Transportation Council and Thurston Regional Planning Council to cooperatively develop and adopt regional transportation plans that will, when implemented, provide people with additional transportation alternatives and choices, reduce greenhouse gases and achieve the statutory benchmarks to reduce annual per capita vehicle miles traveled in those counties with populations greater than 245,000. By December 1, 2011, the Department will report to the Governor on which regional transportation planning organizations have developed, or are developing, plans with greenhouse gas strategies, which strategies appear to have the greatest potential to achieve the benchmarks, and what policy or funding issues need to be resolved to ensure implementation;

3. The Office of the Governor shall work with affected state agencies to develop and seek federal funds to implement a project for the electrification of the West Coast interstate highway and associated metropolitan centers, including request for federal funding to purchase electric vehicles and install public infrastructure for electric and other high-efficiency, zero- or low-carbon vehicles. The Office shall invite the collaboration of the states of Oregon and California and participation by the private sector in developing and implementing this project and in requesting federal support.

4. The Director of the Department of Ecology shall evaluate the potential impacts of sea level rise on the state's shoreline areas, including the potential increases in storm surge and coastal flooding, increased erosion, and loss of habitat and ecosystems, and develop recommendations for addressing these impacts. The Department shall invite the Washington State Association of Counties and the Association of Washington Cities to collaborate in conducting the evaluation and developing recommendations.

5. The Director of the Department of Ecology and the Secretary of the Department of Health, in consultation with other affected state, local and federal agencies, shall develop specific guidelines, tools, and recommendations to assist the state and its water users to meet the anticipated changes in water resources due to climate change impacts.

6. In implementing all aspects of this Executive Order, the state and its agencies shall consult, on a government-to-government basis with Washington's Native American Tribes.

7. The Director of the Department of Ecology, in cooperation with affected agencies shall provide a progress report to the Office of the Governor by December 31, 2010.

Signed and sealed with the official seal of the state of Washington on this 21st day of May 2009 at Seattle, Washington.

By:

/s/
Christine O. Gregoire
Governor

BY THE GOVERNOR:

/s/
Secretary of State

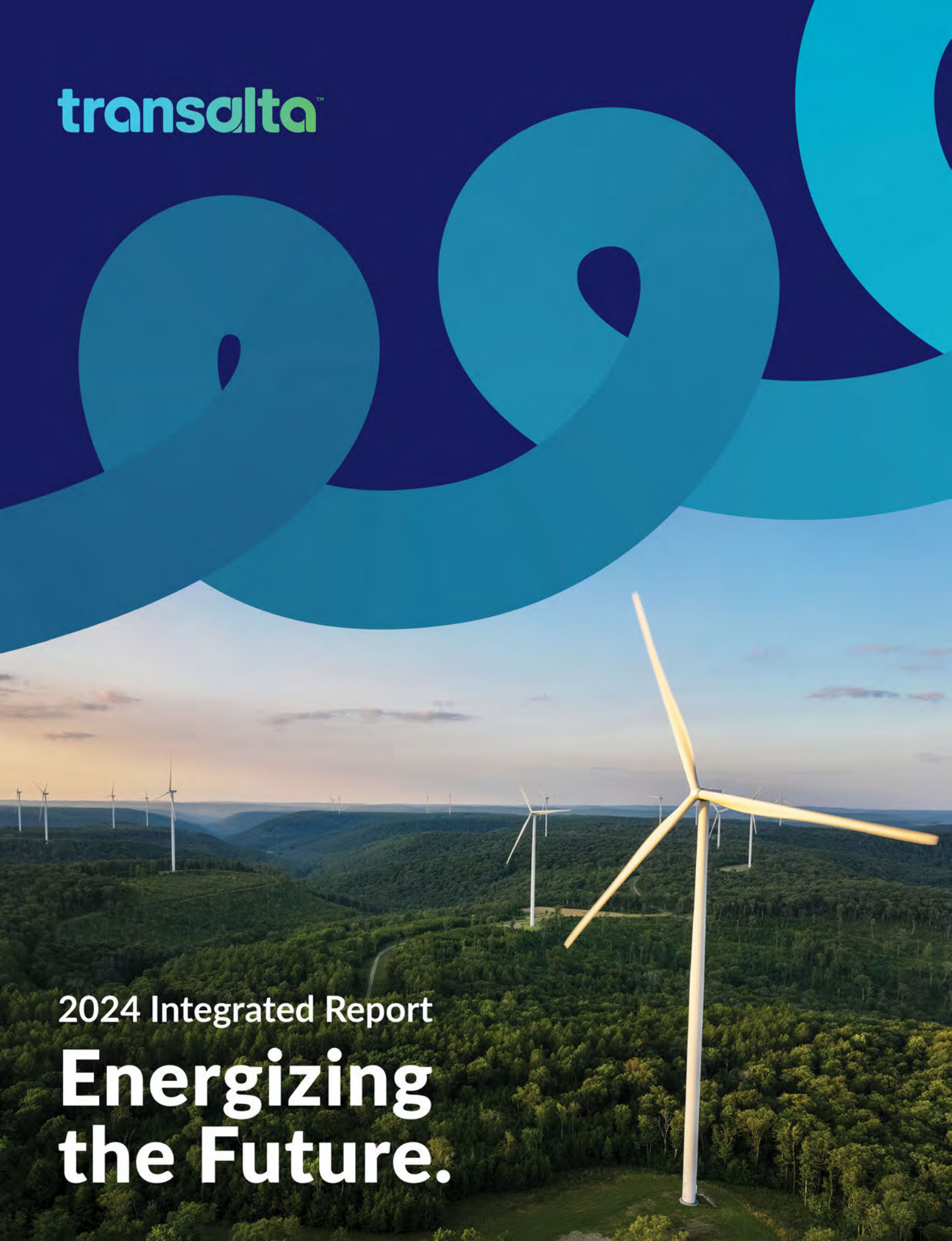
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-115:
TransAlta 2024 Annual Integrated Report

transalta™



2024 Integrated Report

Energizing the Future.



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Letter from the President and CEO

John H. Kousinioris
President and Chief Executive Officer

Dear Fellow Shareholders,

2024 was marked by significant change across our sector, ranging from growing supply chain constraints to rising demand for power and associated reliability products. As I look to 2025 and beyond, I am optimistic about the opportunities for our company. Power markets will continue to evolve, with momentum driven from the growth in demand from electrification and data centres, and the ongoing evolution of the energy mix. While we remain steadfast in the transition to a cleaner electricity future, we recognize the paramount importance of providing reliable generation. All forms of energy will be needed to ensure an orderly transition. As a highly capable, experienced and flexible company, we are well-positioned to drive growth and innovate as we navigate this evolving landscape. We will focus on reliable life extension opportunities within our existing portfolio, a technology-agnostic approach to greenfield development and opportunistic mergers and acquisitions. And we will continue to be disciplined with our capital allocation, focused on maximizing shareholder value, while remaining a trusted partner for our customers.

Sustaining Strong Business Performance

TransAlta was able to achieve another year of strong performance despite significant headwinds, including persistent inflation and lower power prices. We delivered exceptional results, achieving $2.8 billion in revenues and $1.3 billion in adjusted EBITDA. Our net earnings for shareholders were also excellent at $177 million.

On a free cash flow basis, we generated $569 million, at the upper end of our guidance range, or $1.88 per share. Since 2022, we've delivered an impressive $8.65 per share of free cash flow.

In 2024, we returned $143 million to shareholders through our enhanced share repurchase program, at an average price of $10.59 per share. This is part of our capital allocation strategy, which adapts to market conditions and the timing of development at our legacy thermal energy campuses, opportunistic M&A and growth opportunities. We have a normal course issuer bid in place that we have actively used year after year to make accretive share buy backs, with up to $100 million available for share buy backs in 2025.

We have also increased our annual common share dividend for 2025 to $0.26 per common share, as another means of returning free cash flow to our shareholders.

We made significant progress in our growth initiatives in 2024. Our team successfully completed all three Oklahoma wind facilities including White Rock West, White Rock East and Horizon Hill. Additionally, the Mount Keith Transmission Expansion achieved commercial operation earlier in the year. These additions, along with the fully rehabilitated Kent Hills facilities, are expected to contribute over $175 million in EBITDA annually.

Availability was also excellent and reflected a significant improvement across our facilities, at 91.2 per cent fleet-wide in 2024.

Strategic Acquisition of Heartland

In the fourth quarter of 2024, we completed the acquisition of Heartland Generation. The addition of Heartland's assets to our portfolio provides us with a further 1.7 GW of generation capacity in Alberta and British Columbia, adding flexible and complementary capacity to our fleet, including contracted cogeneration and peaking generation, legacy gas-fired thermal generation and transmission capacity. With the growing demand for reliable power and the intermittency of renewables, the need for low-cost, highly flexible and fast-responding generation to support grid reliability is more critical than ever. The Heartland acquisition strengthens our position to meet future demand for reliable electricity with a robust and diversified portfolio.

Leading in Carbon Reductions

We are committed to decarbonization, with a target of reducing scope 1 and 2 greenhouse gas emissions by 75 per cent from 2015 levels by 2026. Since 2018, we have retired 4,464 MW of coal-fired generation capacity and converted 1,659 MW of coal-fired capacity to natural-gas. By the end of 2025, the remaining 670 MW of our coal-fired generation will be retired, marking an important milestone for the company's transition and further reducing our emissions. Our converted natural gas units have approximately 57 per cent lower CO_2 intensity compared to coal-fired generation. Since 2015, we have reduced scope 1 and 2 greenhouse gas emissions by 22.7 MT CO_2e or 70 per cent, a remarkable achievement considering the size and diversity of our fleet.

Disciplined Approach to Capital Allocation and Growth

Electrification and growing demand presents significant opportunities for TransAlta. Our strong balance sheet, diverse generation portfolio and growth pipeline ensure that we are well positioned for the years ahead. Given our skill set, competitive advantages and market positioning, we are poised to capture opportunities in each of our core markets of Canada, the United States and Western Australia.

Long-term shareholder value creation will ultimately drive our investment and capital allocation decisions. Our primary goal is to maximize shareholder returns in the near-term by realizing the value of our legacy thermal energy campuses as we pursue redevelopment opportunities, as well as potential mergers and acquisitions. Longer-term, our focus is on greenfield development.

We remain disciplined in our investment decisions to ensure that we obtain appropriate risk-adjusted returns for our shareholders. As we execute our Growth Plan, we expect our adjusted EBITDA will become increasingly contracted and more diversified across generation type and customer base.

Preparing for TransAlta's Future

Looking ahead to 2025 and beyond, we are prepared to meet the increasing demand for power that stems from electrification and the build-out of data centres supporting the AI revolution. Our legacy fleet ensures that we can maintain a stable cash flow base, while we continue to invest in diverse, flexible and responsive generation to meet future reliability needs.

In 2025, we will be focused on continued safe, reliable operations and executing our strategic priorities. Specifically, optimizing our Alberta Portfolio, executing our growth plan, realizing the value of our legacy generating facilities and maintaining financial strength and capital allocation discipline.

Our strong free cash flow permits us to return capital to our shareholders and invest in TransAlta's future, with a focus on increasing our contracted cash flows and diversifying our generation portfolio. We remain focused on identifying the opportunities and meeting the challenges that will push our company forward in the second half of the decade and into the 2030s.

Our achievements in 2024 would not have been possible without the collective contributions of our employees. I thank them for their continued commitment to our core values of safety, innovation, sustainability, respect, and integrity.

I would also like to express my thanks to our Board of Directors for the support, guidance and wisdom that they provide day after day to our company.

To our shareholders, thank you for your trust and confidence. We greatly value your opinions and put your interests at the centre of our continued transformation and the development of our strategy.

Finally, we sincerely appreciate the support of all of our stakeholders, including our indigenous partners.

I am confident in the future and believe our success will continue in 2025 and beyond.



John H. Kousinioris
President and Chief Executive Officer
February 19, 2025



Message from the Chairman of the Board

John P. Dielwart
Chair of the Board of Directors

Dear Fellow Shareholders,

As we report the financial results for the year ended December 31, 2024, I am incredibly proud to share in TransAlta's accomplishments, which would not have been possible without the contribution of our exceptional employees. The company, under direction of the Board, expanded its renewable portfolio with the commercial operation of our Horizon Hill and White Rock wind facilities, achieved strong operational results and enhanced its Alberta strategy through the completed acquisition of Heartland Generation.

The company continues to manage its evolution for the benefit of our shareholders. We have reported another year of superior results that were within the upper end of the original expectations we had at the beginning of 2024. Our management team delivered another year of strong free cash flow for our shareholders, achieved excellent safety results, continued to reduce our emissions ahead of targets and deployed our capital in a disciplined and prudent way throughout the year. TransAlta has delivered performance at all levels: safety; financial; operational; and sustainability.

The company's evolving strategy continues to provide strong results and 2024's share price appreciation reflects the success of that execution. We continue to transition the company through our technology-agnostic Growth Plan and are well-positioned as a credible and sought-after developer of choice for customers in all of our core geographies.

Our strategy is directed towards achieving material growth in our portfolio that will also increase the size of our contracted fleet by the end of the decade. We will remain disciplined in the deployment of our capital and we will not grow for the sake of growth even if it means we do not achieve our growth plan targets. Creating shareholder value can happen through growth; however, we have multiple avenues to deploy our capital to benefit our shareholders. We will maintain discipline as we consider our growth aspirations and rates of return for growth projects. Acquisitions must also meet our target thresholds for value creation. Long-term shareholder value creation will drive our investment decisions and we remain committed to our prudent capital allocation approach. To the extent we deploy reduced growth capital, we will pursue enhanced shareholder returns through dividends and share repurchases.

The Board wishes to extend our heartfelt gratitude to the employees and leadership team of TransAlta for their efforts in delivering another outstanding year for the company. The team has exhibited exceptional adaptability to the changing market conditions and is committed to enhancing the value of the company in a disciplined and prudent manner. They have a keen focus on capital allocation discipline and creation of shareholder value.

We also thank our shareholders for their unwavering commitment and confidence in the company. As fellow shareholders, we look forward to TransAlta's execution in 2025 and we value your engagement and viewpoints on our evolving strategy.

The Board of Directors will continuously engage with and guide the management team to assess new opportunities that will add value to the company, improve performance and overall increase shareholder value.



John P. Dielwart
Chair of the Board of Directors
February 19, 2025

TRANSALTA CORPORATION Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A) contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. Refer to the Forward-Looking Statements section of this MD&A for additional information.

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*This MD&A should be read in conjunction with our 2024 audited annual consolidated financial statements (the consolidated financial statements) and our 2024 Annual Information Form (AIF), each for the fiscal year ended Dec. 31, 2024. In this MD&A, unless the context otherwise requires, "we", "our", "us", the "Company" and "TransAlta" refer to TransAlta Corporation and its subsidiaries. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) for Canadian publicly accountable enterprises as issued by the International Accounting Standards Board (IASB) and in effect at Dec. 31, 2024. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted, except amounts per share, which are in whole dollars to the nearest two decimals. This MD&A is dated Feb. 19, 2025. Additional information respecting TransAlta, including our AIF for the year ended Dec. 31, 2024, is available on SEDAR+ at **www.sedarplus.ca**, on EDGAR at **www.sec.gov** and on our website at **www.transalta.com**. Information on or connected to our website is not incorporated by reference herein.*

Forward-Looking Statements

This MD&A includes "forward-looking information" within the meaning of applicable Canadian securities laws and "forward-looking statements" within the meaning of applicable U.S. securities laws, including the *Private Securities Litigation Reform Act* of 1995 (collectively referred to herein as "forward-looking statements").

Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "can", "could", "would", "shall", "believe", "expect", "estimate", "anticipate", "intend", "plan", "forecast", "foresee", "potential", "enable", "continue" or other comparable terminology. These statements are not guarantees of our future performance, events or results and are subject to risks, uncertainties and other important factors that could cause our actual performance, events or results to be materially different from those set out in or implied by the forward-looking statements.

In particular, this MD&A contains forward-looking statements about the following, among other things:

- The strategic objectives of the Company and that the execution of the Company's strategy will realize value for shareholders;
- Our capital allocation and financing strategy;
- Our sustainability goals and targets, including those in our 2024 Sustainability Report;
- Our 2025 Outlook;
- Our financial and operational performance, including our hedge position;
- Optimizing and diversifying our existing assets;
- The increasingly contracted nature of our fleet;
- Expectations about strategies for growth and expansion, including opportunities for Centralia redevelopment, and data centre opportunities;
- Expected costs and schedules for planned projects;
- Expected regulatory processes and outcomes, including in relation to the Alberta restructured energy market;
- The power generation industry and the supply and demand of electricity;
- The cyclicality of our business;
- Expected outcomes with respect to legal proceedings;
- The expected impact of future tax and accounting changes; and
- Expected industry, market and economic conditions.

The forward-looking statements contained in this MD&A are based on many assumptions including, but not limited to, the following:

- No significant changes to applicable laws and regulations;
- No unexpected delays in obtaining required regulatory approvals;
- No material adverse impacts to investment and credit markets;
- No significant changes to power price and hedging assumptions;
- No significant changes to gas commodity price assumptions and transport costs;
- No significant changes to interest rates;
- No significant changes to the demand and growth of renewables generation;
- No significant changes to the integrity and reliability of our facilities;
- No significant changes to the Company's debt and credit ratings;
- No unforeseen changes to economic and market conditions; and
- No significant event occurring outside the ordinary course of business.

These assumptions are based on information currently available to TransAlta, including information obtained from third-party sources. Actual results may differ materially from those predicted by such assumptions.

Factors that may adversely impact what is expressed or implied by forward-looking statements contained in this MD&A include, but are not limited to:

- Fluctuations in power prices;
- Changes in supply and demand for electricity;
- Our ability to contract our electricity generation for prices that will provide expected returns;
- Our ability to replace contracts as they expire;
- Risks associated with development projects and acquisitions;
- Any difficulty raising needed capital in the future on reasonable terms or at all;
- Our ability to achieve our targets relating to environmental, social and governance (ESG) performance;
- Long-term commitments on gas transportation capacity that may not be fully utilized over time;
- Changes to the legislative, regulatory and political environments;
- Environmental requirements and changes in, or liabilities under, these requirements;
- Operational risks involving our facilities, including unplanned outages and equipment failure;
- Disruptions in the transmission and distribution of electricity;
- Reductions in production;
- Impairments and/or writedowns of assets;
- Adverse impacts on our information technology systems and our internal control systems, including increased cybersecurity threats;
- Commodity risk management and energy trading risks;

- Reduced labour availability and ability to continue to staff our operations and facilities;
- Disruptions to our supply chains;
- Climate-change related risks;
- Reductions to our generating units' relative efficiency or capacity factors;
- General economic risks, including deterioration of equity markets, increasing interest rates or rising inflation;
- General domestic and international economic and political developments, including potential trade tariffs;
- Industry risk and competition;
- Counterparty credit risks;
- Inadequacy or unavailability of insurance coverage;
- Increases in the Company's income taxes and any risk of reassessments;
- Legal, regulatory and contractual disputes and proceedings involving the Company;
- Reliance on key personnel; and
- Labour relations matters.

The foregoing risk factors, among others, are described in further detail in the Governance and Risk Management section of this MD&A.

Readers are urged to consider these factors carefully when evaluating the forward-looking statements, which reflect the Company's expectations only as of the date hereof and are cautioned not to place undue reliance on them. The forward-looking statements included in this document are made only as of the date hereof and we do not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise, except as required by applicable laws. The purpose of the financial outlooks contained herein is to give the reader information about management's current expectations and plans and readers are cautioned that such information may not be appropriate for other purposes. In light of these risks, uncertainties and assumptions, the forward-looking statements might occur to a different extent or at a different time than we have described, or might not occur at all. We cannot assure that projected results or events will be achieved.

Description of the Business

TransAlta Corporation is one of Canada's largest publicly traded power generators, owning and operating a diverse fleet across Canada, the United States and Western Australia. Our portfolio includes hydro, wind, solar, battery storage, natural gas and coal, complemented by our exceptional asset optimization and energy marketing capabilities. As one of Canada's largest producers of wind and thermal generation and Alberta's largest producer of hydro power, TransAlta remains committed to a balanced, technology-agnostic generation mix. With strong cash flows underpinned by a high-quality portfolio, TransAlta strives to deliver sustainable long-term shareholder value in an evolving energy landscape.

The Company's goal is to deliver solutions to meet our customers' needs for reliable, sustainable power. With over a century of experience, TransAlta is a trusted partner delivering tailored solutions. Our strategic priorities include optimizing our Alberta Portfolio, executing our growth plan, realizing the value of our legacy generating facilities, maintaining financial strength and capital discipline, defining the next generation of power solutions and leading in ESG and market policy development. We are primarily focused on opportunities within our core markets of Canada, the United States and Western Australia.

Our sustainability goals include our commitment to cease coal-fired generation at the end of 2025. We remain on track to achieve our 2026 target of 75 per cent scope 1 and 2 GHG emissions reductions since 2015 and our carbon net-zero goal by 2045. Since 2005, we have reduced our scope 1 and 2 GHG emissions by 32 million tonnes (MT) of CO_2e or an 77 per cent reduction, representing approximately 11 per cent of Canada's Paris Agreement 2030 decarbonization target[(1)].

Portfolio of Assets

Our asset portfolio is geographically diversified with operations across our core markets.

Our Hydro, Wind and Solar, Gas and Energy Transition segments are responsible for operating and maintaining our generation facilities. Our Energy Marketing segment is responsible for marketing and scheduling our merchant asset fleet in North America (excluding Alberta) along with the procurement, transport and storage of natural gas, providing knowledge to support our growth team, and generating a stand-alone gross margin separate from our asset business through a leading North American energy marketing and trading platform.

Our highly diversified portfolio consists of both merchant assets and high-quality contracted assets. Our merchant assets include our unique hydro merchant portfolio and our merchant legacy thermal portfolio and wind assets. Our merchant exposure is primarily in Alberta, where 58 per cent of our capacity is located and 77 per cent of our Alberta capacity is available to participate in the merchant market. Our high-quality contracted assets provide stable long-term cash flow and earnings, balancing our merchant fleet.

In Alberta, the Company manages merchant exposure by executing hedging strategies that include a significant base of commercial and industrial (C&I) customers, supplemented with financial hedges. A significant portion of our thermal generation capacity in Alberta is hedged to provide greater cash flow certainty while also capturing higher returns for our shareholders through the optimization of our merchant generation portfolio. Refer to the 2025 Outlook section and the Optimization of the Alberta Portfolio of this MD&A for further details.

(1) In 2005, TransAlta's estimated scope 1 and 2 GHG emissions were 41.9 MT of CO_2e, which did not receive independent limited assurance. Canada's Paris Agreement 2030 decarbonization target assumed 293 MT of CO_2e or a 40 per cent reduction from a 2005 baseline of 732 MT of CO_2e.

The following table provides our consolidated ownership by segment of our facilities across the regions in which we operate as of Dec. 31, 2024:

	Hydro		Wind & Solar		Gas		Energy Transition		Total	
Year ended Dec. 31, 2024	Gross Installed Capacity (MW)	Number of facilities	Gross Installed Capacity (MW)[1]	Number of facilities	Gross Installed Capacity (MW)[1][2]	Number of facilities[2]	Gross Installed Capacity (MW)	Number of facilities[3]	Gross Installed Capacity (MW)	Number of facilities
Alberta	834	17	764	14	3,650	15	—	—	5,248	46
Canada, excluding Alberta	88	7	751	9	705	4	—	—	1,544	20
U.S.	—	—	1,024	10	29	1	671	2	1,724	13
Western Australia	—	—	48	3	450	6	—	—	498	9
Total	**922**	**24**	**2,587**	**36**	**4,834**	**26**	**671**	**2**	**9,014**	**88**

(1) Gross installed capacity for consolidated reporting is based on a proportionate interest held in a facility. Refer to the Plant Summary section for details.

(2) Includes 1,747 MW of capacity attributable to nine facilities acquired from Heartland, which exclude the Planned Divestitures. Refer to the Significant and Subsequent events section.

(3) Includes the Centralia coal facility and the Skookumchuck hydro facility.

Contracted Capacity

The following table provides our contracted capacity by segment in MW and as a percentage of total gross installed capacity of our facilities across the regions in which we operate as of Dec. 31, 2024:

As at Dec. 31, 2024	Hydro	Wind & Solar	Gas[1]	Energy Transition	Total
Alberta	—	336	887	—	1,223
Canada, excluding Alberta	88	751	705	—	1,544
U.S.	—	1,024	29	381	1,434
Western Australia	—	48	450	—	498
Total contracted capacity (MW)	88	2,159	2,071	381	4,699
Contracted capacity as a % of total capacity (%)	10	83	43	57	52

(1) Includes contracted capacity of 436 MW from facilities acquired from Heartland: 376 MW in Alberta and 60 MW in Canada, excluding Alberta. The figures exclude the contracted capacity of Planned Divestitures. Refer to the Significant and Subsequent events section.

Approximately 52 per cent of our total installed capacity is contracted. Contracts are primarily with strong creditworthy counterparties.

The following table provides the weighted average contract life by segment of our contracted and merchant facilities across the regions in which we operate as of Dec. 31, 2024:

As at Dec. 31, 2024	Hydro	Wind & Solar	Gas[1]	Energy Transition	Total
Alberta	—	7	2	—	3
Canada, excluding Alberta	15	9	7	—	8
U.S.	—	13	1	—	8
Western Australia	—	14	14	—	14
Total weighted average contract life (years)[2]	1	10	4	—	5

(1) Total weighted average contract life calculation of our gas facilities as at Dec. 31, 2024 includes the contracts added from the acquisition of Heartland and excludes the contracts pertaining to Planned Divestitures.

(2) The contract life of merchant facilities is included as nil years.

Highlights

For the year ended Dec. 31, 2024, the Company demonstrated strong financial and operational performance. The results were within the upper range of management's expectations due to active management of the Company's merchant portfolio and hedging strategies. During 2024, the Company settled a higher volume of hedges at prices that were significantly above the spot market in Alberta and achieved commercial operation at the White Rock and Horizon Hill wind facilities. On Dec. 4, 2024, the Company also completed the acquisition of Heartland Generation, which added 1,747 MW to gross installed capacity. IFRS financial results include the Poplar Hill and Rainbow Lake facilities, (collectively, the Planned Divestitures), which the Company agreed to divest pursuant to a consent agreement entered into with the Commissioner of Competition for Canada. Our non-IFRS measures and operational KPIs exclude the results of the Planned Divestitures. Refer to the Significant and Subsequent Events section of this MD&A for details on the Heartland acquisition and the Planned Divestitures.

Year ended Dec. 31	2024	2023	2022[4]
Operational information			
Availability (%)	**91.2**	88.8	89.8
Production (GWh)	**22,811**	22,029	21,258
Select financial information			
Revenues	**2,845**	3,355	2,976
Adjusted EBITDA[1]	**1,253**	1,632	1,656
Earnings before income taxes	**319**	880	353
Net earnings attributable to common shareholders	**177**	644	4
Cash flows			
Cash flow from operating activities	**796**	1,464	877
Funds from operations[1][2]	**810**	1,351	1,346
Free cash flow[1][2]	**569**	890	961
Per share			
Weighted average number of common shares outstanding	**302**	276	271
Net earnings per share attributable to common shareholders, basic and diluted	**0.59**	2.33	0.01
Dividends declared per common share	**0.24**	0.22	0.21
Dividends declared per preferred share	**1.36**	1.33	0.25
Funds from operations per share[1][2]	**2.68**	4.89	4.97
Free cash flow per share[1][2]	**1.88**	3.22	3.55

As at Dec. 31	2024	2023	2022
Liquidity and capital resources			
Available liquidity[5]	**1,616**	1,738	2,118
Adjusted net debt to adjusted EBITDA (times)	**3.6**	2.5	2.1
Total consolidated net debt[1][3]	**3,798**	3,453	2,854
Assets and liabilities			
Total assets	**9,499**	8,659	10,741
Total long-term liabilities[6]	**5,087**	5,253	5,864
Total liabilities[7]	**7,656**	6,995	8,752

(1) These items are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Presenting these items from period to period provides management and investors with the abi ity to evaluate earnings (loss) trends more readily in comparison with prior periods' results. Refer to the Segmented Financial Performance and Operating Results section of this MD&A for further discussion of these items, including, where app icable, reconciliations to measures calculated in accordance with IFRS. Also, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(2) Funds from operations (FFO) per share and free cash flow (FCF) per share are calculated using the weighted average number of common shares outstanding during the period. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for the purpose of these non-IFRS ratios.

(3) Refer to the table in the Financial Capital section of this MD&A for more details on the composition of total conso idated net debt.

(4) During 2024 our adjusted EBITDA composition was amended to exclude the impact of Brazeau penalties and related provisions. Therefore, the Company has applied this composition to all previously reported periods. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(5) Available liquidity is calculated as a sum of total available capacity under the committed credit and term facilities and cash and cash equivalents net of bank overdraft, less the amounts drawn under the non-committed demand faci ities.

(6) Total long-term liabilities correspond to total non-current iabi ities in the conso idated statements of financial position under IFRS .

(7) Total liabilities correspond to a sum of current and non-current iabi ities in the conso idated statements of financial position under IFRS.

Operating Performance

Availability

The following table provides availability (%) by segment:

Year ended Dec. 31	2024	2023	2022
Hydro	**90.7**	90.8	96.7
Wind and Solar	**93.4**	86.9	83.8
Gas	**92.2**	91.6	94.6
Energy Transition[1]	**80.0**	79.8	77.2
Availability (%)	**91.2**	88.8	89.8

(1) Availabi ity adjusted for dispatch optimization for the year ended 2022 was 79 per cent.

Availability is an important measure for the Company as it represents the percentage of time a facility is available to produce electricity and is an indicator of the overall performance of the fleet.

The Company schedules dedicated time (planned outages) to maintain, repair or make improvements to the facilities at a time that will minimize the impact to operations. In high price environments, actual outage schedules may change to accelerate the return to service of the unit.

2024 versus 2023

Availability for the year ended Dec. 31, 2024, was 91.2 per cent, compared to 88.8 per cent in 2023, consistent with management's expectations. Higher availability compared to the prior year was primarily due to:

- The addition of the White Rock and Horizon Hill wind facilities; and
- The return to service of the Kent Hills wind facilities.

2023 versus 2022

Availability for the year ended Dec. 31, 2023, was 88.8 per cent, compared to 89.8 per cent in 2022. Lower availability compared to the prior year was primarily due to:

- Planned outages in the Hydro segment, mainly at our Alberta Hydro Assets, to perform scheduled maintenance; and
- Planned outages at Sundance Unit 6, Sheerness Unit 1, Keephills Units 2 and 3 and Sarnia for scheduled maintenance in the Gas segment; partially offset by
- Lower planned outages at Centralia Unit 2 in the Energy Transition segment; and
- The partial return to service of the Kent Hills wind facilities.

Production and Long-Term Average Generation

The following table provides the long-term average generation (LTA generation) on a consolidated basis for each of our segments:

	2024			2023			2022		
Year ended Dec. 31	Actual production (GWh)	LTA generation (GWh)	Production as a % of LTA	Actual production (GWh)	LTA generation (GWh)	Production as a % of LTA	Actual production (GWh)	LTA generation (GWh)	Production as a % of LTA
Hydro	**1,723**	**2,015**	**86%**	1,769	2,015	88%	1,988	2,015	99%
Wind and Solar	**5,949**	**6,876**	**87%**	4,243	5,127	83%	4,248	4,950	86%
Gas	**12,317**			11,873			11,448		
Energy Transition	**2,822**			4,144			3,574		
Total	**22,811**			22,029			21,258		

In addition to availability, the Company uses LTA generation as another indicator of performance for the renewable facilities whereby actual production levels are compared against the expected long-term average. In the short term, for each of the Hydro and Wind and Solar segments, the conditions will vary from one period to the next. Over longer durations, facilities are expected to produce in line with their long-term averages, which is broadly considered a reliable indicator of performance.

LTA generation is calculated on an annualized basis from the average annual energy yield predicted from our simulation model based on historical resource data performed over a period of typically greater than 25 years.

The LTA generation for Gas and Energy Transition is not applicable as these facilities are dispatchable and their production is largely dependent on market conditions and merchant demand.

2024 versus 2023

Total production for 2024 increased by 782 GWh, or four per cent, compared to 2023, primarily due to:

- Production from new facilities, including the White Rock West and East wind facilities commissioned in January and April 2024, respectively, the Horizon Hill wind facility commissioned in May 2024, and the Northern Goldfields solar facilities commissioned in November 2023;
- Production from the facilities acquired with Heartland;
- Favourable market conditions in the Ontario wholesale power market that enabled higher dispatch at the Sarnia facility in the Gas segment that resulted in higher merchant production to the Ontario grid;
- The return to service of the Kent Hills wind facilities in the first quarter of 2024; and
- Full-year production from the Garden Plain wind facility; partially offset by
- Increased economic dispatch at the Centralia facility due to lower market prices compared to the prior year in the Energy Transition segment; and
- Higher dispatch optimization in Alberta.

2023 versus 2022

Total production for 2023, increased by 771 GWh, or four per cent, compared to 2022, primarily due to:

- Lower planned and unplanned outages at the Centralia facility in the Energy Transition segment compared to prior year, which allowed the Company to increase dispatch during the periods of higher merchant pricing;
- Higher availability in the Gas segment during periods of supply tightness, allowing for the Company to operate during periods of peak pricing;
- Production from new facilities, including the Garden Plain wind facility, commissioned in August 2023 and the Northern Goldfields solar facilities in November 2023; and
- The partial return to service of the Kent Hills wind facilities in the fourth quarter of 2023, partially offset by
- Lower than average wind and water resources in the year;
- Lower availability in the Hydro segment due to increased planned maintenance outages compared to 2022; and
- Relatively mild weather in the fourth quarter of 2023, compared to the same period in 2022 when markets experienced tighter supply due to the extreme cold weather in Alberta.

Market Pricing

Year ended Dec. 31, 2024	2024	2023	2022
Alberta spot power price ($/MWh)	**63**	134	162
Mid-Columbia spot power price (US$/MWh)	**56**	76	82
Ontario spot power price ($/MWh)	**32**	28	47
Natural gas price (AECO) per GJ ($)	**1.29**	2.54	5.08

For the year ended Dec. 31, 2024, spot electricity prices in Alberta were 53 per cent lower compared to 2023, driven by lower natural gas prices and the anticipated increased supply from new renewable and combined-cycle gas facilities.

Spot electricity prices in the Pacific Northwest were 26 per cent lower compared to 2023 due to lower natural gas prices.

AECO natural gas prices for the year ended Dec. 31, 2024, were 49 per cent lower compared to 2023, mainly due to higher gas production and higher storage levels in Alberta and throughout North America.

For the year ended Dec. 31, 2023, spot electricity prices in Alberta and the Pacific Northwest were lower compared to 2022. Lower prices in both regions resulted from lower natural gas prices and overall weaker weather-driven demand in the second half of 2023, with notably lower prices due to above normal weather patterns in the fourth quarter of 2023.

For Alberta specifically, warm weather in the fourth quarter of 2023 resulted in a strong wind resource pattern, which, combined with new installed capacity, added supply in the market compared to the prior year.

AECO natural gas prices for the year ended Dec. 31, 2023, were lower compared to 2022, mainly due to increased production and storage levels in Alberta and North America.

Financial Performance Review of Consolidated Information

Year ended Dec. 31	2024	2023	2022
Revenues	**2,845**	3,355	2,976
Fuel and purchased power	**939**	1,060	1,263
Carbon compliance	**112**	112	78
Operations, maintenance and administration	**655**	539	521
Depreciation and amortization	**531**	621	599
Asset impairment charges (reversals)	**46**	(48)	9
Interest income	**30**	59	24
Interest expense	**324**	281	286
Earnings before income taxes	**319**	880	353
Income tax expense	**80**	84	192
Net earnings attributable to common shareholders	**177**	644	4
Net earnings attributable to non-controlling interests	**10**	101	111

2024 versus 2023

Revenues totalling $2,845 million, decreased by $510 million, or 15 per cent, compared to 2023, primarily due to:

- Lower merchant spot and hedged power prices in the Alberta market;
- Lower revenue from derivatives and other trading activities in the Wind and Solar segment driven by higher unrealized mark-to-market losses on the long-term wind energy sales related to the Oklahoma facilities, primarily due to strengthening forecasted wind capture prices reflected in the year; and
- Lower revenue at Centralia due to higher economic dispatch driven by lower market prices; partially offset by
- Higher revenue from derivatives and other trading activities in the Gas segment driven by higher volume of favourable hedging positions settled, which generated positive contributions over settled spot prices in Alberta;

- Higher environmental and tax attributes revenues from the Hydro segment and the sale of production tax credits from the Oklahoma wind facilities to taxable U.S. counterparties;
- Commercial operation of the White Rock and Horizon Hill wind facilities, the Northern Goldfields solar facilities, the Mount Keith 132kV expansion and return to service of the Kent Hills wind facilities; and
- Higher revenue in the Gas segment with the acquisition of Heartland.

Fuel and purchased power costs totalling $939 million, decreased by $121 million, or 11 per cent, compared to 2023, primarily due to:

- Lower purchased power costs driven by lower Mid-Columbia prices on repurchases of power;
- Lower fuel consumption due to higher dispatch optimization in the Gas segment in Alberta and higher economic dispatch in the Energy Transition segment; and
- Lower natural gas prices.

Carbon compliance costs totalling $112 million, were consistent with 2023, primarily due to:

- Utilization of internally generated and externally purchased emission credits to settle a portion of our 2023 GHG obligation; offset by
- An increase in the carbon price from $65 per tonne in 2023 to $80 per tonne in 2024; and
- Higher production in the Gas segment.

OM&A expenses totalling $655 million, increased by $116 million, or 22 per cent, compared to 2023, primarily due to:

- Penalties assessed by the Alberta Market Surveillance Administrator for self-reported contraventions pertaining to hydro ancillary services provided during 2021 and 2022;
- Higher spend to support strategic and growth initiatives;
- The addition of the White Rock and Horizon Hill wind facilities and the return to service of the Kent Hills wind facilities;
- The Heartland acquisition-related transaction and restructuring costs, mainly comprising severance, legal and consulting fees; and
- Higher spending related to the planning and design of an upgrade to our enterprise resource planning (ERP) system.

Depreciation and amortization totalling $531 million, decreased by $90 million, or 14 per cent, compared to 2023, primarily due to:

- Revisions to useful lives of certain facilities in prior and current periods; partially offset by
- Commercial operation of the White Rock and Horizon Hill wind facilities and return to service of the Kent Hills wind facilities.

Asset impairment charges totalling $46 million, increased by $94 million, compared to asset impairment recoveries in 2023, primarily due to:

- An increase in decommissioning and restoration provisions on retired assets driven by a decrease in discount rates and revisions in estimated decommissioning costs; and
- Impairment charges related to development projects that are no longer proceeding.

Interest income totalling $30 million, decreased by $29 million, or 49 per cent, compared to 2023, primarily due to lower cash balances and lower interest rates.

Interest expense totalling $324 million, increased by 43 million, or 15 per cent, compared to 2023, primary due to lower capitalized interest resulting from lower construction activity in 2024 compared to 2023.

Earnings before income taxes totalling $319 million, decreased by $561 million, or 64 per cent, compared to 2023, due to the above noted items. Refer to the Segment Financial Performance and Operating Results section for additional information.

Income tax expense totalling $80 million, decreased by $4 million, or five per cent, compared to 2023, due to:

- Lower earnings before income taxes due to the above noted items; partially offset by
- A recovery related to the reversal of previously derecognized Canadian deferred tax assets.

Net earnings attributable to non-controlling interests totalling $10 million, decreased by $91 million, or 90 per cent, compared to 2023, primarily due to lower net earnings for TransAlta Cogeneration, LP (TA Cogen) resulting from lower merchant pricing in the Alberta market and the acquisition of TransAlta Renewables Inc. (TransAlta Renewables) on Oct. 5, 2023.

2023 versus 2022

Revenues totalling $3,355 million, increased by $379 million, or 13 per cent, compared to 2022, primarily due to:

- Higher realized and unrealized gains from hedging and derivative positions across the segments; partially offset by
- Lower revenue from merchant sales due to lower spot power prices and production in Alberta.

Fuel and purchased power costs totalling $1,060 million, decreased by $203 million, or 16 per cent, compared to 2022, primarily due to:

- Lower natural gas commodity pricing; partially offset by
- Higher fuel usage in both the Gas and Energy Transition segments.

Carbon compliance costs totalling $112 million, increased by $34 million, or 44 per cent, compared to 2022, primarily due to:

- An increase in the carbon price per tonne from $50 per tonne in 2022 to $65 per tonne in 2023;
- Higher production in the Gas segment; and
- No utilization of emission credits to settle GHG obligations as was done in the prior year.

OM&A expenses totalling $539 million, increased by $18 million, or three per cent, compared to 2022, primarily due to:

- Higher spending on strategic and growth initiatives;
- Higher costs associated with the relocation of the Company's head office; and
- Increased costs due to inflationary pressures.

Depreciation and amortization totalling $621 million, increased by $22 million, or four per cent, compared to 2022, primarily due to:

- Revisions to useful lives of certain facilities; and
- Commercial operation of new facilities.

Asset impairment reversals totalling $48 million, increased by $57 million, compared to an asset impairment charge in 2022, primarily due to:

- decommissioning and restoration provisions for retired assets being favourably impacted by a change in timing of expected cash outflows, partially offset by lower discount rates, resulting in a net impairment reversal of $34 million; and
- A Hydro segment impairment reversal of $10 million due to a contract extension and favourable changes in power price assumptions.

Interest income totalling $59 million, increased by $35 million, or 146 per cent, compared to 2022, primarily due to higher cash balances and favourable interest rates.

Earnings before income taxes totalling $880 million, increased by $527 million, or 149 per cent, compared to 2022, due to the above noted items.

Income tax expense totalling $84 million, decreased by $108 million, or 56 per cent, compared to 2022, due to a recovery relating to the reversal of previously derecognized Canadian deferred tax assets and lower U.S. non-deductible expenses relating to U.S. operations, partially offset by higher earnings from Canadian operations.

Net earnings attributable to non-controlling interests totalling $101 million, decreased by $10 million, or nine per cent, compared to 2022, primarily due to lower net earnings for TA Cogen.

Adjusted EBITDA — 2024 versus 2023

For the year ended Dec. 31, 2024, the Company's adjusted EBITDA was $1,253 million as compared to $1,632 million in 2023, a decrease of $379 million, or 23 per cent. The major factors impacting adjusted EBITDA are summarized in the following table:

	Year ended Dec. 31
Adjusted EBITDA for the year ended Dec. 31, 2023	1,632
Hydro: Lower primarily due to lower spot power prices and ancillary services prices in the Alberta market, partially offset by realized premiums above the spot power prices, higher environmental and tax attributes revenues due to higher sales of emission credits to third parties and intercompany sales to the Gas segment and higher ancillary service volumes due to increased demand by the Alberta Electric System Operator (AESO).	(143)
Wind and Solar: Higher primarily due to new sales of production tax credits, the return to service of the Kent Hills wind facilities, the commercial operation of the White Rock and Horizon Hill wind facilities, partially offset by lower realized power pricing in the Alberta market and higher OM&A due to the addition of new wind facilities.	59
Gas: Lower primarily due to lower power prices in the Alberta market and resulting increase in economic dispatch, an increase in the price of carbon, higher carbon costs and fuel usage related to production and lower capacity payments, partially offset by a higher volume of favourable hedging positions settled, the utilization of emission credits to settle a portion of our 2023 GHG obligation and lower natural gas prices.	(266)
Energy Transition: Lower primarily due to increased economic dispatch driven by lower market prices which negatively impacted merchant production, partially offset by lower fuel and purchased power costs.	(31)
Energy Marketing: Higher primarily due to favourable market volatility and the timing of realized settled trades during the current year in comparison to the prior year and lower OM&A.	22
Corporate: Lower primarily due to higher spend to support strategic and growth initiatives.	(20)
Adjusted EBITDA[(1)] for the year ended Dec. 31, 2024	**1,253**

(1) Adjusted EBITDA is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A. For a comparison of 2024 and 2023 earnings before income tax, the most directly comparable IFRS measure, see pages M67-M68

Adjusted EBITDA — 2023 versus 2022

For the year ended Dec. 31, 2023, the Company's adjusted EBITDA was $1,632 million compared to $1,656 million in 2022, a decrease of $24 million. The major factors impacting adjusted EBITDA are summarized in the following table:

	Year ended Dec. 31
Adjusted EBITDA for the year ended Dec. 31, 2022[1]	1,656
Hydro: Lower primarily due to lower ancillary services volumes, lower spot power and ancillary services prices in the Alberta market, lower production due to lower availability and lower than average water resources, partially offset by realized gains from hedging strategy and sales of environmental attributes.	(90)
Wind and Solar: Lower primarily due to lower environmental attribute revenues, lower realized power prices in Alberta, lower wind resource across the operating fleet, lower liquidated damages recognized at the Windrise wind facility and higher OM&A, partially offset by the commercial operation of the Garden Plain wind facility, the Northern Goldfields solar facilities and the partial return to service of the Kent Hills wind facilities.	(54)
Gas: Higher primarily due to higher power price hedges partially offsetting the impacts of lower Alberta spot prices, lower natural gas commodity costs and higher production, partially offset by lower thermal revenues, higher carbon prices and higher carbon costs and fuel usage related to production.	172
Energy Transition: Higher primarily due to higher production from higher availability and merchant sales volumes, partially offset by lower market prices compared to the prior year.	36
Energy Marketing: Lower primarily due to lower realized settled trades during the year on market positions in comparison to prior year and higher OM&A.	(74)
Corporate: Lower primarily due to increased spending to support strategic and growth initiatives and higher costs associated with the relocation of the Company's head office.	(14)
Adjusted EBITDA[2] for the year ended Dec. 31, 2023	**1,632**

(1) During 2024 our adjusted EBITDA composition was amended to exclude the impact of Brazeau penalties and related provisions. Therefore, the Company has applied this composition to all previously reported periods. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A. For a comparison of 2023 and 2022 earnings before income tax, the most directly comparable IFRS measure, see pages M68-M69.

Free Cash Flow — 2024 versus 2023

For the year ended Dec. 31, 2024, the Company's FCF decreased by $321 million, or 36 per cent, compared to 2023, but was within the upper range of our expected full-year financial guidance. The major factors impacting FCF are summarized in the following table:

	Year ended Dec. 31
FCF for the year ended Dec. 31, 2023	890
Lower Adjusted EBITDA due to the items noted above.	(379)
Higher current income tax expense due to the full utilization of Canadian non-capital loss carryforwards in 2023, partially offset by lower earnings before income taxes in 2024 compared to the prior year.	(93)
Higher net interest expense[1] due to lower capitalized interest resulting from lower construction activity in 2024 compared to 2023 and lower interest income due to lower cash balances and interest rates in 2024 compared to prior year.	(67)
Lower distributions paid to subsidiaries' non-controlling interests relating to lower TA Cogen net earnings resulting from lower merchant pricing in the Alberta market and the cessation of distributions to TransAlta Renewables non-controlling interest. On Oct. 5, 2023, the Company acquired all of the outstanding common shares of TransAlta Renewables not already owned, directly or indirectly.	183
Higher provisions accrued in the current year compared to the prior year resulting in higher FCF.	11
Lower sustaining capital expenditures due to the receipt of a lease incentive related to the Company's head office, and lower planned major maintenance at our Alberta and Western Australian gas facilities, partially offset by higher major maintenance at our Alberta Hydro facilities.	32
Other non-cash items[2]	14
Other[3]	(22)
FCF[4] for the year ended Dec. 31, 2024	**569**

(1) Net interest expense includes interest expense less interest income and excludes non-cash items ike financing amortization and accretion.

(2) Other non-cash items consists of Alberta market pool incentives, carbon ob igation and contract liabilities. Refer to the Reconci iation of Cash Flow from Operations to FFO and FCF section tables in this MD&A for more details.

(3) Other consists of higher realized foreign exchange loss, higher decommissioning and restoration costs settled, higher dividends paid on preferred shares, lower principal payments on lease liabi ities and lower productivity capital. Refer to the Reconciliation of Cash Flow from Operations to FFO and FCF section tables in this MD&A for more details.

(4) FCF is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A. For a comparison of 2024 and 2023 cash flow from operations, the most directly comparable IFRS measure, see page M56.

Free Cash Flow — 2023 versus 2022

For the year ended Dec. 31, 2023, the Company's FCF decreased by $71 million, or 7 per cent, compared to 2022, and was in line with our revised expected full-year financial guidance. The major factors impacting FCF are summarized in the following table:

	Year ended Dec. 31
FCF for the year ended Dec. 31, 2022	961
Lower Adjusted EBITDA due to the items noted above.	(24)
Higher interest income due to higher cash balances and favourable interest rates.	35
Lower current income tax expense due to previously restricted non-capital loss carryforwards that were utilized to offset taxable income.	15
Higher sustaining capital expenditures due to higher planned major maintenance costs for the Hydro and Gas segments, partially offset by lower planned major maintenance in the Wind and Solar and Energy Transition segments.	(32)
Higher distributions paid to subsidiaries' non-controlling interests related to the timing of distributions paid to TA Cogen, partially offset by lower distributions paid to TransAlta Renewables.	(36)
Lower provisions being accrued compared to the prior year, with no notable settlements being recorded in either year.	(26)
Other non-cash items[1]	11
Other[2]	(14)
FCF[3] for the year ended Dec. 31, 2023	**890**

(1) Other non-cash items consists of Alberta market pool incentives, carbon obligation, contract liabilities, the SunHills royalty onerous contract and Brazeau penalties. Refer to the Reconci iation of Cash Flow from Operations to FFO and FCF section tables in this MD&A for more details.

(2) Other consists of higher realized foreign exchange loss, higher decommissioning and restoration costs settled, higher dividends paid on preferred shares and higher principal payments on lease liabilities. Refer to the Reconci iation of Cash Flow from Operations to FFO and FCF section tables in this MD&A for more details.

(3) FCF is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A. For a comparison of 2023 and 2022 cash flow from operations, the most directly comparable IFRS measure, see page M57.

Capital Expenditures

Sustaining Capital Expenditures

We are in a long-cycle business that requires significant capital expenditures. Our goal is to undertake sustaining capital expenditures that ensure our facilities operate reliably and safely.

The Company's sustaining capital expenditures by segment are summarized in the table below:

Year ended Dec. 31	2024	2023	2022
Hydro	**56**	41	35
Wind and Solar	**20**	15	18
Gas	**52**	76	41
Energy Transition	**12**	15	19
Corporate	**2**	27	29
Sustaining capital expenditures	**142**	174	142

Total sustaining capital expenditures in 2024 were $32 million lower compared to 2023, primarily due to:

- The receipt of a lease incentive related to the Company's head office, included in the Corporate segment; and
- Lower planned major maintenance at our Alberta and Western Australian gas facilities; partially offset by
- Higher major maintenance at our Alberta hydro assets; and
- Higher major maintenance at our Wind and Solar facilities.

Total sustaining capital expenditures in 2023 were $32 million higher compared to 2022, primarily due to:

- Higher planned major maintenance at our Alberta Hydro assets;
- Higher planned major maintenance at our Sarnia, Sundance Unit 6 and Keephills Units 2 and 3 facilities in the Gas segments; partially offset by
- Lower planned major maintenance in the Wind and Solar segment primarily due to a reduction in major component replacements; and
- Lower planned outage work performed in the Energy Transition segment.

Growth and Development Expenditures

Growth and development expenditures are impacted by the timing and construction of projects within the development pipeline. The following table provides our growth and development spending by segment:

Year ended Dec. 31	2024	2023	2022
Hydro	**9**	6	2
Wind and Solar	**64**	673	711
Gas	**59**	60	61
Growth and development expenditures	**132**	739	774

Growth and development expenditures were lower in 2024 compared to 2023 and 2022, as many of the development projects achieved commercial operation in the first half of 2024. The White Rock East and Horizon Hill wind facilities were commissioned in the second quarter of 2024. The White Rock West wind facility and Mount Keith 132kV expansion were commissioned in the first quarter of 2024.

Refer to the Strategic Priorities section of this MD&A for more details.

In 2023 and 2022, the growth and development expenditures incurred primarily related to:

- The Garden Plain wind facility, which achieved commercial operation in August 2023;
- The Northern Goldfields solar facilities, which achieved commercial operation in November 2023;
- The White Rock and the Horizon Hill wind projects; and
- The Mount Keith 132kV expansion.

Significant and Subsequent Events

Declared Increase in Common Share Dividend

The Company's Board of Directors has approved a $0.02 annualized increase to the common share dividend, or 8 per cent increase, and declared a dividend of $0.065 per common share to be payable on July 1, 2025 to shareholders of record at the close of business on June 1, 2025. The quarterly dividend of $0.065 per common share represents an annualized dividend of $0.26 per common share.

TransAlta Acquires Heartland Generation from Energy Capital Partners

On Dec. 4, 2024, the Company closed the acquisition of Heartland Generation Ltd. and certain affiliates (collectively, Heartland) for a purchase price of $542 million from an affiliate of Energy Capital Partners (ECP), the parent of Heartland (the Transaction). To meet the requirements of the federal Competition Bureau, the Company entered into a consent agreement with the Commissioner of Competition pursuant to which TransAlta agreed to divest Heartland's Poplar Hill and Rainbow Lake assets (the Planned Divestitures) following closing of the Transaction. In consideration of the Planned Divestitures, TransAlta and ECP agreed to a reduction of $80 million from the original purchase price for the Transaction. ECP will be entitled to receive the proceeds from the sale of Poplar Hill and Rainbow Lake, net of certain adjustments following completion of the Planned Divestitures. TransAlta also received a further $95 million at closing of the Transaction to reflect the economic benefit of the Heartland business arising from Oct. 31, 2023 to the closing date of the Transaction, pursuant to the terms of the share purchase agreement. The net cash payment for the Transaction, before working capital adjustments, totalled $215 million, and was funded through a combination of cash on hand and draws on TransAlta's credit facilities.

Excluding the Planned Divestitures, the Transaction adds 1,747 MW (net interest) of complementary capacity from nine facilities, including contracted cogeneration and peaking generation, legacy gas-fired thermal generation, and transmission capacity, all of which will be critical to support reliability in the Alberta electricity market.

Mothballing of Sundance Unit 6

On Nov. 4, 2024, the Company provided notice to the AESO that Sundance Unit 6 will be mothballed on April 1, 2025, for a period of up to two years depending on market conditions. TransAlta maintains the flexibility to return the mothballed unit to service when market fundamentals improve or opportunities to contract are secured. The unit remains available and fully operational for the first quarter of 2025.

Appointment of New Chief Financial Officer (CFO)

The Board appointed Joel Hunter as Executive Vice President, Finance and CFO, effective July 1, 2024.

Production Tax Credit (PTC) Sale Agreements

On Feb. 22, 2024, the Company entered into 10-year transfer agreements with an AA- rated customer for the sale of approximately 80 per cent of the expected PTCs to be generated from the White Rock and the Horizon Hill wind facilities.

On June 21, 2024, the Company entered into an additional 10-year transfer agreement with an A+ rated customer for the sale of the remaining 20 per cent of the expected PTCs.

The expected average annual EBITDA from the two agreements is approximately $78 million (US$57 million).

Normal Course Issuer Bid (NCIB)

TransAlta remains committed to enhancing shareholder returns through appropriate capital allocation such as share buybacks and its quarterly dividend. In the first quarter of 2024, the Company announced an enhanced common share repurchase program for 2024, allocating up to $150 million, and targeting up to 42 per cent of 2024 FCF guidance, to be returned to shareholders in the form of share repurchases and dividends.

On May 27, 2024, the Company announced that it had received approval from the Toronto Stock Exchange to purchase up to 14 million common shares during the 12-month period that commenced May 31, 2024, and terminates May 31, 2025. Any common shares purchased under the NCIB will be cancelled.

For the year ended Dec. 31, 2024, the Company purchased and cancelled a total of 13,467,400 common shares, at an average price of $10.59 per common share, for a total cost of $143 million, including taxes.

Horizon Hill Wind Facility Achieves Commercial Operation

On May 21, 2024, the 202 MW Horizon Hill wind facility achieved commercial operation. The facility is located in Logan County, Oklahoma and is fully contracted to Meta Platforms Inc. for the offtake of 100 per cent of the generation.

White Rock Wind Facilities Achieve Commercial Operation

On Jan. 1, 2024, the 100 MW White Rock West wind facility achieved commercial operation. On April 22, 2024, the 202 MW White Rock East wind facility also completed commissioning. The facilities are located in Caddo County, Oklahoma and are contracted under two long-term power purchase agreements (PPAs) with Amazon Energy LLC for the offtake of 100 per cent of the generation.

Mount Keith 132kV Expansion Complete

The Mount Keith 132kV expansion project was completed during the first quarter of 2024. The expansion was developed under the existing PPA with BHP Nickel West (BHP), which extends until Dec. 31, 2038. The expansion will facilitate the connection of additional generating capacity to the transmission network which supports BHP's operations.

Segmented Financial Performance and Operating Results

Segmented information is prepared on the same basis that the Company manages its business, evaluates financial results and makes key operating decisions. The following table reflects the summary financial information on a consolidated basis for the year ended Dec. 31:

	Adjusted EBITDA[1]		
Year ended Dec. 31	**2024**	**2023**	**2022[2]**
Hydro	**316**	459	549
Wind and Solar	**316**	257	311
Gas	**535**	801	629
Energy Transition	**91**	122	86
Energy Marketing	**131**	109	183
Corporate	**(136)**	(116)	(102)
Total adjusted EBITDA[1]	**1,253**	1,632	1,656
Earnings before income taxes	**319**	880	353

(1) This item is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(2) During 2024 our adjusted EBITDA composition was amended to exclude the impact of Brazeau penalties and related provisions. Therefore, the Company has applied this composition to all previously reported periods. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

2024 versus 2023

Earnings before income taxes for the year ended Dec. 31, 2024, decreased by $561 million, or 64 per cent, compared to 2023, primarily due to:

- The factors causing lower adjusted EBITDA above;
- Higher asset impairment charges related to an increase in the decommissioning provision on retired assets, driven by a decrease in discount rates and revisions in estimated decommissioning costs, and higher impairment charges related to development projects that are no longer proceeding;
- Lower unrealized mark-to-market gains and lower realized gains on closed exchange positions in the Energy Marketing segment mainly driven by market volatility across North American power and natural gas markets;
- Higher unrealized mark-to-market losses recorded in the Wind and Solar segment primarily related to the long-term wind energy sales related to the Oklahoma facilities;
- Higher interest expense due to lower capitalized interest during 2024 resulting from lower construction activity in 2024 compared to 2023;
- Lower capacity payments in 2024 for Southern Cross Energy in Western Australia due to the scheduled conclusion on Dec. 31, 2023, of the demand capacity charge under the customer contract, partially offset by the commencement in March 2024 of capacity payments for the Mount Keith 132kV expansion;
- Heartland acquisition-related transaction and restructuring costs;
- Lower interest income due to lower cash balances and lower interest rates during 2024;
- Higher spending relating to planning and design work on a planned upgrade to our ERP system; and
- Penalties assessed by the Alberta Market Surveillance Administrator for self-reported contraventions pertaining to Hydro ancillary services provided during 2021 and 2022; partially offset by
- Lower depreciation and amortization compared to 2023 related to revisions of useful lives of certain facilities in prior and current periods, partially offset by the commercial operation of new facilities during the year and the return to service of the Kent Hills wind facilities;
- Higher unrealized mark-to-market gains recorded in the Energy Transition segment primarily related to the favourable changes in forward prices; and
- Higher net other operating income mainly due to Sundance A decommissioning cost reimbursement.

2023 versus 2022

Earnings before income taxes for the year ended Dec. 31, 2023, increased by $527 million, or 149 per cent, compared to 2022, primarily due to:

- Higher unrealized mark-to-market gains in in the Gas segment primarily related to higher power price hedges;
- Higher unrealized mark-to-market gains in the Wind and Solar segment primarily related to Garden Plain and Big Level, partially offset by unrealized mark-to-market losses related to the Oklahoma facilities;
- Higher realized mark-to-market losses on closed exchange positions in the Energy Marketing segment mainly driven by market volatility across the North American power and natural gas markets;
- Higher asset impairment reversals for the Hydro and Wind and Solar segments due to favourable changes in power price assumptions and contract extensions, partially offset by a change in decommissioning and restoration provisions for retired assets due to a change in the timing of expected cash outflows and the revisions in discount rates;
- Higher interest income due to higher cash balances and favourable interest rates; partially offset by
- Lower adjusted EBITDA (as described above);
- Lower gain on sale of assets in 2023. In 2022 the Company closed the sale of two hydro facilities and sold equipment related to its Energy Transition segment; and
- Higher depreciation and amortization due to revisions to useful lives of certain facilities and commercial operation of new facilities.

Hydro

Year ended Dec. 31	2024	2023	Change		2022[7]	Change	
Gross installed capacity (MW)	**922**	**922**	—	— %	922	—	— %
LTA generation (GWh)	**2,015**	**2,015**	—	— %	2,015	—	— %
Availability (%)	**90.7**	**90.8**	*(0.1)*	— %	96.7	*(5.9)*	*(6)%*
Production							
Contract production (GWh)	**281**	**277**	*4*	*1 %*	323	*(46)*	*(14)%*
Merchant production (GWh)	**1,442**	**1,492**	*(50)*	*(3)%*	1,665	*(173)*	*(10)%*
Total energy production (GWh)	**1,723**	**1,769**	*(46)*	*(3)%*	1,988	*(219)*	*(11)%*
Ancillary service volumes (GWh)[1]	**2,951**	**2,582**	*369*	*14 %*	3,124	*(542)*	*(17)%*
Alberta Hydro Assets revenues[2][3]	**144**	**291**	*(147)*	*(51)%*	328	*(37)*	*(11)%*
Other Hydro Assets and other revenues[2][4]	**49**	**51**	*(2)*	*(4)%*	42	*9*	*21 %*
Alberta Hydro ancillary services revenues	**136**	**173**	*(37)*	*(21)%*	256	*(83)*	*(32)%*
Environmental and tax attributes revenues	**61**	**14**	*47*	*336 %*	1	*13*	*1300 %*
Adjusted revenues[5]	**390**	**529**	*(139)*	*(26)%*	627	*(98)*	*(16)%*
Fuel and purchased power	**16**	**19**	*(3)*	*(16)%*	22	*(3)*	*(14)%*
Adjusted gross margin[6]	**374**	**510**	*(136)*	*(27)%*	605	*(95)*	*(16)%*
Adjusted OM&A[5]	**55**	**48**	*7*	*15 %*	53	*(5)*	*(9)%*
Taxes, other than income taxes	**3**	**3**	—	— %	3	—	— %
Adjusted EBITDA[6]	**316**	**459**	*(143)*	*(31)%*	549	*(90)*	*(16)%*
Supplemental Information:							
Gross revenues per MWh							
Alberta Hydro Assets energy ($/MWh)[2][3]	**100**	**195**	*(95)*	*(49)%*	197	*(2)*	*(1)%*
Alberta Hydro Assets ancillary ($/MWh)[1]	**46**	**67**	*(21)*	*(31)%*	76	*(9)*	*(12)%*

(1) Ancillary services as described in the AESO Conso idated Authoritative Document Glossary.

(2) Alberta Hydro Assets include 13 hydro faci ities on the Bow and North Saskatchewan river systems. Other Hydro Assets include our hydro facilities in British Columbia, Ontario and Alberta (other than the Alberta Hydro Assets).

(3) Alberta Hydro Assets revenues include revenues from swaps and forward hedges.

(4) Other revenues includes revenues from our transmission business and other contractual arrangements, including the flood mitigation agreement with the Government of Alberta and black start services.

(5) For details of the adjustments to revenues and OM&A included in adjusted EBITDA refer to the Additional IFRS and Non-IFRS Measures section of this MD&A.

(6) Adjusted EBITDA and adjusted gross margin are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS and Non-IFRS Measures section of this MD&A.

(7) During 2024 our adjusted EBITDA composition was amended to exclude the impact of Brazeau penalties and related provisions. Therefore, the Company has applied this composition to all previously reported periods. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

2024 versus 2023

Adjusted revenues for the year ended Dec. 31, 2024, decreased compared to 2023, primarily due to:

- Lower spot power prices and ancillary services prices in the Alberta market; partially offset by
- Realized premiums above spot power prices and positive contributions from hedging;
- Higher environmental and tax attributes revenues due to increased sales of emission credits to third parties and intercompany sales to the Gas segment; and
- Higher ancillary services volumes due to increased demand by the AESO.

Adjusted EBITDA for the year ended Dec. 31, 2024, decreased compared to 2023, primarily due to lower adjusted revenues as explained by the factors above.

For further discussion on the Alberta market conditions and pricing, refer to the Alberta Electricity Portfolio section of this MD&A.

2023 versus 2022

Adjusted revenues for the year ended Dec. 31, 2023, decreased compared to 2022, primarily due to:

- Lower ancillary services volumes due to the AESO procuring lower volumes given its decision to reduce the cumulative volume of imports into Alberta;
- Lower spot power prices and ancillary services prices in the Alberta market; and
- Lower production due to lower availability from planned outages at our Alberta Hydro Assets and lower than average water resources; partially offset by
- Realized gains from our hedging strategy for the Alberta Hydro Assets; and
- Sales of environmental attributes driven by an increase in emission credit sales.

Adjusted EBITDA for the year ended Dec. 31, 2023, decreased compared to 2022, primarily due to lower adjusted revenues as explained by the factors above.

Wind and Solar

Year ended Dec. 31	2024	2023	Change		2022	Change	
Gross installed capacity (MW)[1]	**2,587**	**2,084**	*503*	*24 %*	1,906	*178*	*9 %*
LTA generation (GWh)	**6,876**	**5,127**	*1,749*	*34 %*	4,950	*177*	*4 %*
Availability (%)	**93.4**	**86.9**	*6.5*	*7 %*	83.8	*3.1*	*4 %*
Production							
Contract production (GWh)	**4,720**	**3,095**	*1,625*	*53 %*	3,182	*(87)*	*(3)%*
Merchant production (GWh)	**1,229**	**1,148**	*81*	*7 %*	1,066	*82*	*8 %*
Total production (GWh)	**5,949**	**4,243**	*1,706*	*40 %*	4,248	*(5)*	*— %*
Revenues	**372**	**347**	*25*	*7 %*	357	*(10)*	*(3)%*
Environmental and tax attributes revenues	**77**	**26**	*51*	*196 %*	50	*(24)*	*(48)%*
Adjusted revenues[2]	**449**	**373**	*76*	*20 %*	407	*(34)*	*(8)%*
Fuel and purchased power	**30**	**30**	*—*	*— %*	31	*(1)*	*(3)%*
Carbon compliance	**—**	**—**	*—*	*— %*	1	*(1)*	*(100)%*
Adjusted gross margin[3]	**419**	**343**	*76*	*22 %*	375	*(32)*	*(9)%*
Adjusted OM&A[2]	**97**	**80**	*17*	*21 %*	68	*12*	*18 %*
Taxes, other than income taxes	**16**	**12**	*4*	*33 %*	12	*—*	*— %*
Net other operating income	**(10)**	**(6)**	*(4)*	*67 %*	(16)	*10*	*(63)%*
Adjusted EBITDA[3]	**316**	**257**	*59*	*23 %*	311	*(54)*	*(17)%*

(1) Gross installed capacity and availability for 2024 include the 100 MW White Rock West and 202 MW White Rock East wind facilities that achieved commercial operation in January and April 2024, respectively, and the 202 MW Horizon Hill wind faci ity that achieved commercial operation in May 2024.Tower removal at Sinott in 2025, reduced gross installed capacity by 1 MW. Gross installed capacity and availabi ity for 2024 and 2023 include the 130 MW Garden Plain wind facility that achieved commercial operation in August 2023 and the 48 MW Northern Goldfields solar facilities that achieved commercial operation in November 2023.

(2) For details of the adjustments to revenues and OM&A included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A. The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(3) Adjusted EBITDA and adjusted gross margin are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS and Non-IFRS Measures section of this MD&A.

2024 versus 2023

Adjusted revenues for the year ended Dec. 31, 2024, increased compared to 2023, primarily due to:

- Higher environmental and tax attributes revenues from the sale of production tax credits from Horizon Hill and White Rock West and East wind facilities to taxable US counterparties;
- Higher production from the return to service of the Kent Hills wind facilities; and
- Commercial operation of the Horizon Hill and White Rock West and East wind facilities; partially offset by
- Lower realized power prices in the Alberta market.

Adjusted EBITDA for the year ended Dec. 31, 2024, increased compared to the same period in 2023, primarily due to:

- Higher adjusted revenues as explained by the factors above; partially offset by
- Higher OM&A mainly due to the addition of new wind facilities.

2023 versus 2022

Adjusted revenues for the year ended Dec. 31, 2023, decreased compared to 2022, primarily due to:

- Lower environmental attribute revenues driven by a reduction of offsets and emission credit sales;
- Lower realized power prices in Alberta; and
- Weaker than long-term average wind resource across the operating fleets; partially offset by
- Commercial operation of the Garden Plain wind facility and the Northern Goldfield Solar facilities in the third and fourth quarter, respectively; and
- The partial return to service of the Kent Hills wind facilities.

Adjusted EBITDA for the year ended Dec. 31, 2023, decreased compared to the same period in 2022, primarily due to:

- Lower adjusted revenues as explained by the factors above;
- Higher OM&A related to salary escalations, higher insurance costs and long-term service agreement escalations; and
- Lower liquidated damages recognized at the Windrise wind facility.

Gas

Year ended Dec. 31	2024	2023	Change		2022	Change	
Gross installed capacity (MW)[1]	**4,834**	**3,084**	*1,750*	*57 %*	3,084	—	— %
Availability (%)	**92.2**	**91.6**	*0.6*	*1 %*	94.6	*(3.0)*	*(3)%*
Production							
Contract sales volume (GWh)	**6,874**	**4,322**	*2,552*	*59 %*	3,806	*516*	*14 %*
Merchant sales volume (GWh)	**6,576**	**7,889**	*(1,313)*	*(17)%*	7,927	*(38)*	— %
Purchased power (GWh)[2]	**(1,133)**	**(338)**	*(795)*	*235 %*	(285)	*(53)*	*19 %*
Total production (GWh)	**12,317**	**11,873**	*444*	*4 %*	11,448	*425*	*4 %*
Adjusted revenues[3]	**1,321**	**1,525**	*(204)*	*(13)%*	1,521	*4*	— %
Adjusted fuel and purchased power[3]	**470**	**449**	*21*	*5 %*	637	*(188)*	*(30)%*
Carbon compliance	**145**	**112**	*33*	*29 %*	83	*29*	*35 %*
Adjusted gross margin[4]	**706**	**964**	*(258)*	*(27)%*	801	*163*	*20 %*
OM&A	**198**	**192**	*6*	*3 %*	195	*(3)*	*(2)%*
Taxes, other than income taxes	**13**	**11**	*2*	*18 %*	15	*(4)*	*(27)%*
Net other operating income	**(40)**	**(40)**	—	— %	(38)	*(2)*	*5 %*
Adjusted EBITDA[4]	**535**	**801**	*(266)*	*(33)%*	629	*172*	*27 %*

(1) Gross installed capacity and availability for 2024 include the 1,747 MW Heartland gas facilities and exclude the Planned Divestitures. Refer to the Significant and Subsequent events section. Gross installed capacity for Keephills Unit 3 was adjusted by 3 MW during 2024 due to reduced equipment load.

(2) Power required to fulfil contractual obligations during planned and unplanned outages is included in purchased power.

(3) For details of the adjustments to revenues and fuel and purchased power included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(4) Adjusted EBITDA and adjusted gross margin are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

2024 versus 2023

The Gas fleet performance was broadly in line with management's expectations for the segment.

Adjusted revenues for the year ended Dec. 31, 2024, decreased compared to 2023, primarily due to:

- Lower power prices in the Alberta market;
- Increased dispatch optimization from Alberta Gas facilities driven by lower power prices; and
- Lower capacity payments in 2024 for Southern Cross Energy in Western Australia due to the scheduled conclusion on Dec. 31, 2023, of the demand capacity charge under the customer contract, partially offset by the commencement in March 2024 of capacity payments for the Mount Keith 132kV expansion; partially offset by
- Higher volume of favourable hedging positions settled, which generated positive contributions over settled spot prices in Alberta.

Adjusted EBITDA for the year ended Dec. 31, 2024, decreased compared to 2023, primarily due to:

- Lower adjusted revenues explained above;
- An increase in the carbon price from $65 to $80 per tonne, impacting gross margin from our Canadian gas facilities; and
- Higher carbon costs and fuel usage related to production; partially offset by
- The utilization of emission credits to settle a portion of our 2023 GHG obligation; and
- Lower natural gas prices.

2023 versus 2022

Adjusted revenues for the year ended Dec. 31, 2023, increased compared to 2022, primarily due to:

- Higher production due to the fleet being available during periods of supply tightness and peak pricing; and
- Higher power price hedges, partially offsetting the impact of lower Alberta spot prices; partially offset by
- Lower thermal revenues due to lower steam revenue pricing at the Sarnia facility compared to 2022.

Adjusted EBITDA for the year ended Dec. 31, 2023, increased compared to 2022, primarily due to:

- Lower natural gas commodity costs for the Alberta Gas facilities; and
- Higher adjusted revenues explained above; partially offset by
- Higher carbon costs and fuel usage related to production with the utilization of emission credits to settle a portion of the GHG obligation in 2022; and
- Carbon price increases from $50 per tonne to $65 per tonne, impacting our Canadian gas facilities.

Energy Transition

Year ended Dec. 31	2024	2023	Change		2022	Change	
Gross installed capacity (MW)	**671**	**671**	—	— %	671	—	— %
Availability (%)	**80.0**	**79.8**	0.2	— %	77.2	2.6	3 %
Production							
Contract sales volume (GWh)	**3,338**	**3,329**	9	— %	3,329	—	— %
Merchant sales volume (GWh)	**3,201**	**4,417**	(1,216)	(28)%	3,951	466	12 %
Purchased power (GWh)[1]	**(3,717)**	**(3,602)**	(115)	3 %	(3,706)	104	(3)%
Total production (GWh)	**2,822**	**4,144**	(1,322)	(32)%	3,574	570	16 %
Adjusted revenues[2]	**582**	**746**	(164)	(22)%	724	22	3 %
Fuel and purchased power	**418**	**557**	(139)	(25)%	566	(9)	(2)%
Carbon compliance	**1**	**—**	1	— %	(1)	1	(100)%
Adjusted gross margin[3]	**163**	**189**	(26)	(14)%	159	30	19 %
OM&A	**69**	**64**	5	8 %	69	(5)	(7)%
Taxes, other than income taxes	**3**	**3**	—	— %	4	(1)	(25)%
Adjusted EBITDA[3]	**91**	**122**	(31)	(25)%	86	36	42 %
Supplemental information:							
Highvale mine reclamation spend	**11**	**15**	(4)	(27)%	12	3	25 %
Centralia mine reclamation spend	**16**	**13**	3	23 %	16	(3)	(19)%

(1) All of the power produced by Centralia is sold by the Energy Marketing segment for physical market delivery, which is shown as merchant sales volumes. Power required to fulfil contractual ob igations is included in purchased power. Total production from the facility includes the net result of merchant sales volumes and purchased power.

(2) For details of the adjustments to revenues included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(3) Adjusted EBITDA and adjusted adjusted gross margin are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

2024 versus 2023

Adjusted revenues for the year ended Dec. 31, 2024, decreased compared to 2023, primarily due to increased economic dispatch driven by lower market prices which negatively impacted merchant production.

Adjusted EBITDA for the year ended Dec. 31, 2024, decreased compared to 2023, primarily due to:

- Lower revenues as explained by the factors above; partially offset by
- Lower fuel and purchased power costs due to lower Mid-Columbia prices on purchases of power and lower production volumes.

Mine reclamation spending for the year ended Dec. 31, 2024, was consistent with 2023.

2023 versus 2022

Adjusted revenues for the year ended Dec. 31, 2023, increased compared to 2022, primarily due to:

- Higher production from higher availability due to lower planned and unplanned outages at Centralia Unit 2; and
- Less economic dispatch leading to higher merchant sales volumes; partially offset by
- Lower market prices.

Adjusted EBITDA for the year ended Dec. 31, 2023, increased compared to 2022, primarily due to:

- Higher revenues as explained by the factors above;
- Lower purchased power costs due to lower pricing and increased volumes of production; and
- Lower OM&A expenses due to the retirement of Sundance Unit 4 in the first quarter of 2022.

Mine reclamation spending for the year ended Dec. 31, 2023, was consistent with 2022.

Energy Marketing

Year ended Dec. 31	2024	2023	Change		2022	Change	
Adjusted revenues[1]	167	152	15	10 %	218	(66)	(30)%
OM&A	36	43	(7)	(16)%	35	8	23 %
Adjusted EBITDA[2]	131	109	22	20 %	183	(74)	(40)%

(1) For details of the adjustments to revenues included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

2024 versus 2023

Adjusted revenues and Adjusted EBITDA for the year ended Dec. 31, 2024, increased compared to 2023, primarily due to favourable market volatility across North American power and natural gas markets and higher realized settled trades in 2024 in compared to the prior year, primarily due to:

- The Company was able to capitalize on volatility in the trading of both physical and financial power and gas products across North American deregulated markets while maintaining the overall risk profile of the business unit; and
- A decrease in OM&A mainly due to lower incentives related to revenue before adjustments compared to the prior year.

2023 versus 2022

Adjusted revenues and Adjusted EBITDA for the year ended Dec. 31, 2023, decreased compared to 2022. This was in line with management's expectations, but lower year-over-year, primarily due to:

- Lower realized settled trades during the year on market positions in comparison to the prior year; and
- An increase in OM&A mainly due to higher incentives related to revenues before adjustments.

Corporate

Year ended Dec. 31	2024	2023	Change		2022	Change	
Adjusted OM&A[1]	135	115	20	17%	101	14	14%
Taxes, other than income taxes	1	1	—	—%	1	—	—%
Adjusted EBITDA[2]	(136)	(116)	(20)	17%	(102)	(14)	14%

(1) For details of the adjustments to OM&A included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

2024 versus 2023

Adjusted EBITDA for the year ended Dec. 31, 2024, decreased compared to 2023, primarily due to increased spending to support strategic and growth initiatives related to early stage growth projects.

2023 versus 2022

Adjusted EBITDA for the year ended Dec. 31, 2023, decreased compared to 2022, primarily due to:

- Increased spending to support strategic and growth initiatives;
- Higher costs associated with the relocation of the Company's head office; and
- Increased costs due to inflationary pressures.

Performance by Segment with Supplemental Geographical Information

The following table provides adjusted EBITDA by segment across the regions we operate in:

Year ended Dec. 31, 2024	Hydro	Wind & Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	307	51	340	(10)	131	(136)	683
Canada, excluding Alberta	9	122	91	—	—	—	222
U.S.	—	135	12	101	—	—	248
Western Australia	—	8	92	—	—	—	100
Adjusted EBITDA[1]	**316**	**316**	**535**	**91**	**131**	**(136)**	**1,253**
Earnings before income taxes							**319**

Year ended Dec. 31, 2023	Hydro	Wind & Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	451	77	571	(10)	109	(116)	1,082
Canada, excluding Alberta	8	95	89	—	—	—	192
U.S.	—	84	10	132	—	—	226
Western Australia	—	1	131	—	—	—	132
Adjusted EBITDA[1]	459	257	801	122	109	(116)	1,632
Earnings before income taxes							880

(1) Adjusted EBITDA is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Optimization of the Alberta Portfolio

Our merchant exposure is primarily in Alberta, where 58 per cent of our capacity is located, 77 per cent of which is available to participate in the merchant market. Our portfolio of assets consists of hydro, wind, battery storage and natural gas generation facilities.

The acquisition of Heartland enhances and further diversifies TransAlta's competitive portfolio in the highly dynamic and shifting electricity landscape in Alberta, by adding 507 MW of contracted cogeneration capacity, 387 MW of contracted and merchant peaking generation capacity, 950 MW of natural gas-fired thermal generation capacity, transmission capacity and a development pipeline. The fast-ramping nature of certain Heartland facilities is ideally positioned to respond to expected price volatility and deliver peaking capacity in periods of higher demand in the Alberta market. Refer to the Significant and Subsequent events section.

Generating capacity in Alberta is subject to market forces. Power from commercial generation is cleared through a wholesale electricity market. Power is dispatched in accordance with an economic merit order administered by the Alberta Electric System Operator (AESO), based upon offers by generators to sell power in the real-time energy-only market. Our merchant Alberta fleet operates under this framework and we internally manage our offers to sell power.

Optimization of portfolio performance in the Alberta merchant market is driven by the diversity of fuel types, which enables portfolio management. It also provides us with capacity that can be monetized as either energy production or ancillary services. A significant portion of the generation capacity in the portfolio has been hedged to provide greater cash flow certainty. The Company's hedging strategy includes maintaining a significant base of Commercial and Industrial (C&I) customers and is supplemented with financial hedges.

During periods of low market prices, the Company may choose not to generate power from the thermal fleet and monetize its hedged or contract positions. This results in a change in revenue not correlating with a change in production. During 2024, there were periods of low market prices, and the Company opted not to generate production from the thermal fleet, and as a result, the thermal generation sold through C&I contracts and financial hedges exceeded the actual merchant production generated.

The Alberta hydro fleet provides ancillary services and grid reliability products such as black start services, in the event of a system-wide blackout in the province, and drought mitigation, by systematically regulating river flows.

Our Alberta wind and hydro fleets provide a steady stream of environmental credits that the Company sells to third parties and intercompany to the Gas segment.

The following table provides information for the Company's Alberta electricity portfolio:

	2024					2023					2022				
Year ended Dec. 31	Hydro	Wind & Solar	Gas[4]	Energy Transition	Total	Hydro	Wind & Solar	Gas	Energy Transition	Total	Hydro	Wind & Solar	Gas	Energy Transition	Total
Gross installed capacity (MW)	834	764	3,650	—	5,248	834	766	1,960	—	3,560	834	636	1,960	—	3,430
Total production[1] (GWh)	1,443	1,981	8,385	—	11,809	1,492	1,907	8,360	—	11,759	1,665	1,686	8,106	19	11,476
Contract production (GWh)	—	928	2,566	—	3,494	—	774	861	—	1,635	—	620	526	—	1,146
Merchant production (GWh)	1,443	1,053	5,819	—	8,315	1,492	1,133	7,499	—	10,124	1,665	1,066	7,580	19	10,330
Purchased power (GWh)	—	—	(918)	—	(918)	—	—	(150)	—	(150)	—	—	(197)	—	(197)
Hedged production (GWh)	558	136	8,386		9,080	378	221	7,173	—	7,550	—	—	7,228	—	7,228
Production contracted or hedged (%)	39%	54%	131%	—%	106%	25%	41%	96%	—%	78%	—%	37%	96%	—%	73%
Hedged production as a percentage of gross installed capacity (%)	8%	2%	26%	—%	20%	5%	3%	42%	—%	24%	—%	—%	42%	—%	24%
Revenues[2][3][5] ($)	370	105	887	5	1,367	509	130	1,083	5	1,727	602	155	989	6	1,752
Fuel ($)	6	11	297	1	315	8	17	307	—	332	10	17	419	5	451
Purchased power ($)	7	3	60	—	70	9	3	29	—	41	8	4	23	—	35
Carbon compliance[3] ($)	—	—	125	1	126	—	—	106	—	106	—	1	70	(1)	70
Gross margin[5] ($)	357	91	405	3	856	492	110	641	5	1,248	584	133	477	2	1,196

(1) Total production includes contract and merchant production.

(2) Revenues have been adjusted to exclude the impact of unrealized mark-to-market gains or losses and to include realized gains and losses on closed exchange positions.

(3) The intercompany sales of emission credits from the Hydro segment to the Gas segment are eliminated on conso idation in the Corporate segment. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(4) Gross installed capacity for Alberta faci ities in 2024 includes 1,687 MW from the acquisition of Heartland and excludes production from Planned Divestitures. Refer to the Significant and Subsequent events section.

(5) During 2024 our adjusted EBITDA composition was amended to exclude the impact of Brazeau penalties and related provisions. Therefore, the Company has applied this composition to all previously reported periods. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

2024 versus 2023

Total production for the Alberta portfolio for the year ended Dec. 31, 2024, was 11,809 GWh, compared to 11,759 GWh in 2023. The increase of 50 GWh, or 0.4 per cent, was primarily due to:

- Higher production in the Gas segment due to the addition of gas facilities from the acquisition of Heartland; and
- A full-year of production from the addition of the Garden Plain wind facility, which was commissioned in August 2023; partially offset by
- Higher dispatch optimization in the Gas segment; and
- Lower production from the Alberta Hydro Assets due to lower water resources compared to the prior year.

Hedged production for the year ended Dec. 31, 2024, increased compared to 2023. In anticipation of the risk of lower prices in 2024, the Company deployed a defensive strategy to increase financial hedges for the merchant portfolio at attractive margins. Realized gains and losses on financial hedges are included in revenues in the table above.

Gross margin for the Alberta portfolio for the year ended Dec. 31, 2024, was $856 million, compared to $1,248 million in 2023. The decrease of $392 million, or 31 per cent, was primarily due to:

- The impact of lower Alberta spot power prices and lower hydro ancillary services prices;
- Increased dispatch optimization in the Gas segment driven by lower power prices;
- An increase in the carbon price per tonne from $65 in 2023 to $80 in 2024; partially offset by
- Higher gains realized on financial hedges settled in the period;
- Higher environmental and tax attributes revenues due to the increased sales of emission credits to third parties and intercompany sales from the Hydro segment to the Gas segment;
- The utilization of emission credits in the Gas segment in 2024 to settle a portion of our 2023 GHG obligation;
- Higher hydro ancillary services volumes due to increased demand by the AESO; and
- Lower natural gas prices.

2023 versus 2022

Total production for the year ended Dec. 31, 2023, was 11,759 GWh, compared to 11,476 GWh in 2022. The increase of 283 GWh, or two per cent, was primarily due to:

- The commercial operation of the Garden Plain wind facility in the third quarter of 2023;
- Higher production from our Gas facilities due to strong market conditions in the first half of 2023; partially offset by
- Lower water resources in the Alberta Hydro Assets.

Hedged production for the year ended Dec. 31, 2023, increased compared to 2022, primarily due to the opportunity to secure additional margins with strategic hedges for the hydro assets.

Gross margin for the Alberta portfolio for the year ended Dec. 31, 2023, was $1,248 million, compared to $1,196 million in 2022. The increase of $52 million, or four per cent, was primarily due to:

- Higher power price hedges, partially offsetting the impacts of lower Alberta spot prices; and
- Lower natural gas prices compared to 2022; partially offset by
- Lower ancillary services revenues due to the AESO procuring lower volumes given its decision to reduce the cumulative volume of imports into Alberta.

The following table provides information for the Company's Alberta electricity portfolio:

Year ended Dec. 31	2024	2023	2022
Alberta Market			
Spot power price average per MWh	**63**	134	162
Natural gas price (AECO) per GJ	**1.29**	2.54	5.08
Carbon compliance price per tonne	**80**	65	50
Alberta Portfolio Results			
Realized merchant power price per MWh[1]	**109**	136	126
Hydro energy spot power price per MWh	**91**	175	197
Hydro ancillary services price per MWh	**46**	67	76
Wind energy spot power price per MWh	**35**	73	90
Gas spot power price per MWh	**86**	162	194
Hedged power price average per MWh[2]	**84**	111	86
Hedged volume (GWh)	**9,080**	7,550	7,228
Fuel cost per MWh[3]	**38**	40	56
Carbon compliance cost per MWh[4]	**15**	13	9

(1) Rea ized merchant power price for the Alberta electricity portfolio is the average price realized as a result of the Company's merchant power sales and portfolio optimization activities (excluding assets under long-term contract and ancillary revenues) divided by total merchant GWh produced.

(2) Hedged power price average per MWh is calculated as the average sales price for all hedges and direct customer sales during the reporting period.

(3) Fuel cost per MWh is calculated on production from carbon-emitting generation in the Gas and Energy Transition segments.

(4) Carbon compliance cost per MWh is calculated on production from carbon-emitting generation, as well as power purchased, in the Gas and Energy Transition segments.

2024 versus 2023

The average spot power price per MWh for the Alberta portfolio for the year ended Dec. 31, 2024 decreased from $134 per MWh in 2023 to $63 per MWh in 2024, primarily due to:

- Higher generation from the addition of increased supply of new renewables and combined-cycle gas facilities into the market compared to the prior period; and
- Lower natural gas prices.

The realized merchant power price per MWh of production for the Alberta portfolio for the year ended Dec. 31, 2024, decreased by $27 per MWh, compared to 2023, primarily due to:

- Lower average spot power prices as explained above; and
- Lower hedge prices compared to the prior year.

Fuel cost per MWh for the year ended Dec. 31, 2024, decreased by $2 per MWh, compared to 2023, primarily due to lower natural gas prices.

Carbon compliance cost per MWh of production for the year ended Dec. 31, 2024, increased by $2 per MWh, compared to 2023, primarily due to:

- The increase in carbon pricing from $65 per tonne in 2023 to $80 per tonne in 2024; partially offset by
- The utilization of emission credits to settle a portion of the 2023 GHG obligation during the year.

2023 versus 2022

The average spot power price per MWh for the year ended Dec. 31, 2023 decreased from $162 per MWh in 2022 to $134 per MWh in 2023, primarily due to:

- Moderate temperatures in the last six months of the year compared with the prior year;
- Higher total renewable generation in the Alberta market from new Wind and Solar facilities and higher wind resources during the fourth quarter of 2023; and
- Lower natural gas prices.

Realized merchant power price per MWh of production for the Alberta portfolio for the year ended Dec. 31, 2023, increased by $10 per MWh, compared to 2022, primarily due to:

- Optimization of our available capacity across all fuel types; and
- Higher hedge prices compared to the prior year.

Fuel cost per MWh for the Alberta portfolio for the year ended Dec. 31, 2023, decreased by $16 per MWh, compared to 2022, primarily due to lower natural gas prices.

Carbon compliance cost per MWh of production for the Alberta portfolio for the year ended Dec. 31, 2023, increased by $4 per MWh, compared to 2022 primarily due to:

- The increase in carbon pricing from $50 per tonne in 2022 to $65 per tonne in 2023; and
- No utilization of emission credits to settle the GHG obligation during the year. In 2022 the Company used emission credits to settle a portion of the carbon compliance obligation resulting in a lower carbon cost per MWh.

Fourth Quarter Highlights

For the quarter ended Dec. 31, 2024, the Company's performance was impacted by lower power prices in the Alberta and Mid-Columbia markets. The results were in line with management's expectations due to active management of the Company's merchant portfolio and hedging strategies. During the fourth quarter of 2024, the Company settled a higher volume of hedges that were significantly above average spot prices. The acquisition of Heartland on Dec. 4, 2024 positively contributed to the production in the Gas segment and further diversifies TransAlta's competitive portfolio in the highly dynamic and shifting electricity landscape in Alberta by adding 1,747 MW to gross installed capacity.

Consolidated Financial Highlights

Three months ended Dec. 31	2024	2023
Operational information		
Availability (%)	**87.8**	86.9
Production (GWh)	**6,199**	5,783
Select financial information		
Revenues	**678**	624
Adjusted EBITDA[(1)]	**285**	289
Loss before income taxes	**(51)**	(35)
Net loss attributable to common shareholders	**(65)**	(84)
Cash flows		
Cash flow from operating activities	**215**	310
Funds from operations[(1)]	**137**	229
Free cash flow[(1)]	**48**	121
Per share		
Weighted average number of common shares outstanding	**298**	308
Free cash flow per share[(1)(2)]	**0.16**	0.39

(1) These items are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Segmented Financial Performance and Operating Results section of this MD&A for further discussion of these items, including, where app icable, reconciliations to measures calculated in accordance with IFRS. Also, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(2) FFO per share and FCF per share are calculated using the weighted average number of common shares outstanding during the period. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for the purpose of these non-IFRS ratios.

Operating Performance

Availability

The following table provides availability (%) by segment:

Three months ended Dec. 31	2024	2023
Hydro	**85.8**	76.6
Wind and Solar	**92.2**	90.3
Gas[1]	**84.1**	89.5
Energy Transition	**91.7**	79.6
Availability (%)	**87.8**	86.9

(1) Availabi ity for 2024 includes the facilities acquired from Heartland and excludes the Planned Divestitures. Refer to the Significant and Subsequent events section.

Availability for the three months ended Dec. 31, 2024, was 87.8 per cent compared to 86.9 per cent for the same period in 2023, primarily due to:

- The addition of the White Rock and Horizon Hill wind facilities which operated with high availability;
- The return to service of the Kent Hills wind facilities;
- Higher availability in the Hydro segment due to lower planned outages;
- Higher availability in the Energy Transition segment due to lower unplanned outages; and
- Positive contribution from the addition of the gas facilities acquired with Heartland; partially offset by
- Lower availability for the Gas segment due to planned outages at Sarnia, Sheerness and Keephills.

Production and Long-Term Average Generation

	2024			2023		
Three months ended Dec. 31	Actual production (GWh)	LTA generation (GWh)	Production as a % of LTA	Actual production (GWh)	LTA generation (GWh)	Production as a % of LTA
Hydro	**452**	**447**	**101%**	326	447	73%
Wind and Solar	**1,831**	**2,175**	**84 %**	1,479	1,361	109 %
Gas[1]	**2,875**			2,892		
Energy Transition	**1,041**			1,086		
Total	**6,199**			5,783		

(1) Gas production for 2024 includes 511 GWh from Heartland, excluding production from the Planned Divestitures. Refer to the Significant and Subsequent events section.

Production for the three months ended Dec. 31, 2024, was 6,199 GWh compared to 5,783 GWh for the same period in 2023. The increase was primarily due to:

- Higher production in the Wind and Solar segment due to the addition of the Horizon Hill and the White Rock West and East wind facilities during 2024;
- Higher production in the Hydro segment compared to the same period in 2023 due to water conservation in the fourth quarter of 2023 that resulted in lower production volumes compared to the current period; partially offset by
- Lower production in the Energy Transition segment due to higher dispatch optimization, which negatively affected merchant production; and
- Lower production in the Gas segment driven by lower availability at the Sarnia facility due to planned outages, higher economic dispatch in Alberta and lower production from Western Australia due to lower demand, partially offset by positive contribution from the Heartland gas facilities.

Financial Performance Review on Consolidated Information

Three months ended Dec. 31	2024	2023
Revenues	**678**	624
Fuel and purchased power	**249**	278
Carbon compliance	**39**	27
Operations, maintenance and administration	**234**	150
Depreciation and amortization	**143**	132
Asset impairment charges	**20**	26
Interest expense	**92**	66
Foreign exchange gain (loss)	**17**	(7)
Loss before income taxes	**(51)**	(35)
Income tax (recovery) expense	**(8)**	19
Net loss attributable to common shareholders	**(65)**	(84)
Net (loss) earnings attributable to non-controlling interests	**(4)**	5

Current Year Variance Analysis (Fourth quarter 2024 versus Fourth quarter 2023)

Revenues for the three months ended Dec. 31, 2024, increased by $54 million, or nine per cent, compared to the same period in 2023, primarily due to:

- Higher revenue in the Gas segment due to favourable contribution from hedging and the addition of Heartland facilities;
- Higher revenues in the Hydro segment due to higher production in the fourth quarter of 2024 due to water conservation in the same period of 2023; and
- Revenue from the commercial operation of the White Rock and Horizon Hill wind facilities in the current period; partially offset by
- Lower realized power prices and dispatch optimization in Alberta;
- Lower revenues in the Energy Marketing segment due to lower market volatility across North American power and natural gas markets; and
- Lower revenues in the Energy Transition segment due to increased economic dispatch due to lower market prices.

Fuel and purchased power costs for the three months ended Dec. 31, 2024, decreased by $29 million, or 10 per cent, compared to the same period in 2023, primarily due to:

- Lower purchased power costs driven by lower Mid-Columbia prices on repurchases of power and lower production in the Energy Transition segment.

Carbon compliance costs for the three months ended Dec. 31, 2024, increased by $12 million compared to 2023 due to:

- Carbon price increase from $65 to $80 per tonne; and
- Carbon compliance costs attributable to facilities acquired from Heartland.

OM&A expenses for the three months ended Dec. 31, 2024, increased by $84 million, or 56 per cent, compared to the same period in 2023, primarily due to:

- Penalties assessed by the Alberta Market Surveillance Administrator for self-reported contraventions pertaining to hydro ancillary services provided during 2021 and 2022;
- Heartland acquisition-related transaction and restructuring costs;
- Higher spending in connection with planning and design work on a planned upgrade to our ERP system;
- Addition of OM&A costs from Heartland;
- Higher maintenance costs at the South Hedland facility; and
- Higher spend to support strategic and growth initiatives.

Depreciation and amortization for the three months ended Dec. 31, 2024, increased by $11 million, or eight per cent, compared to the same period in 2023, primarily due to:

- Commercial operation of the White Rock and Horizon Hill wind facilities; partially offset by
- Revisions to the useful lives of certain facilities.

Asset impairment charges for the three months ended Dec. 31, 2024 decreased by $6 million, or 23 per cent, compared to the same period in 2023, primarily due to:

- Lower decommissioning and restoration provisions on retired assets driven by lower discount rates in the current period compared to the same period in 2023; partially offset by
- Impairment charges related to development projects that are no longer proceeding.

Interest expense for the three months ended Dec. 31, 2024 increased by $26 million, or 39 per cent, compared to 2023, primarily due to lower capitalized interest in 2024 as a result of capital projects being completed in the first half of 2024.

Foreign exchange gains for the three months ended Dec. 31, 2024 increased by $24 million due to favorable changes in foreign exchange rates.

Loss before income taxes for the three months ended Dec. 31, 2024 totalling $51 million, increased by $16 million, or 46 per cent, compared to the same period in 2023, due to the above noted items.

Income tax recovery for the three months ended Dec. 31, 2024, increased by $27 million, or 142 per cent, compared to 2023 as a result of a higher loss before income taxes due to the above noted items; in addition to lower non-deductible expenses.

Net loss attributable to common shareholders for the three months ended Dec. 31, 2024 was $65 million compared to a net loss of $84 million in the same period of 2023, an improvement of $19 million, or 23 per cent, primarily due to the above noted items.

Net earnings (loss) attributable to non-controlling interests for the three months ended Dec. 31, 2024, decreased by $9 million, or 180 per cent, compared to the same period in 2023, primarily due to lower TA Cogen net earnings resulting from lower Alberta market merchant pricing.

Segmented Financial Performance and Operating Results for the Fourth Quarter

A summary of our adjusted EBITDA by segment and loss before income taxes for the three months ended Dec. 31, 2024, and 2023 is as follows:

	Adjusted EBITDA[1]	
Three months ended Dec. 31	**2024**	**2023**
Hydro	**57**	56
Wind and Solar	**95**	82
Gas	**116**	141
Energy Transition	**28**	26
Energy Marketing	**27**	14
Corporate	**(38)**	(30)
Total adjusted EBITDA[1]	**285**	289
Loss before income taxes	**(51)**	(35)

(1) This item is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Loss before income taxes for the three months ended Dec. 31, 2024, increased by $16 million, or 46 per cent, compared to the same period in 2023, primarily due to:

- Factors causing lower adjusted EBITDA (as described above);
- Higher interest expense due to lower capitalized interest in the fourth quarter of 2024 resulting from lower capital activity in 2024 compared to the same period in 2023;
- Heartland acquisition-related transaction and restructuring costs in the fourth quarter of 2024;
- Higher ERP upgrade costs related to planning and design work;
- Penalties assessed by the Alberta Market Surveillance Administrator for self-reported contraventions pertaining to Hydro ancillary services provided during 2021 and 2022;
- Higher depreciation and amortization due to the commercial operation of the White Rock and Horizon Hill wind facilities during 2024;
- Higher taxes other than income taxes mainly consisting of property taxes due to the addition of new wind facilities during 2024; partially offset by
- Higher realized and unrealized foreign exchange gains;
- Lower realized gains on closed exchange positions in 2024 compared to the same period in 2023;
- Higher net other operating income mainly due to Sundance A decommissioning cost reimbursement; and
- Lower asset impairment charges related to the decommissioning and restoration provisions on retired assets driven by lower discount rates in the current period compared to the same period in 2023, partially offset by impairment charges related to development projects that are no longer proceeding.

The major factors impacting adjusted EBITDA for the three months ended Dec. 31, 2024, are summarized in the following table:

	Three months ended Dec. 31
Adjusted EBITDA for the three months ended Dec. 31, 2023	289
Hydro: Higher due to higher merchant revenues driven by higher volumes, partially offset by lower spot power prices and lower environmental and tax attributes revenues.	1
Wind and Solar: Higher due to environmental and tax attributes revenues from the sale of production tax credits from Horizon Hill and White Rock West and East wind facilities to taxable US counterparties, higher revenues driven by increased production from the addition of the White Rock and Horizon Hill wind facilities and the return to service of the Kent Hills wind facilities, partially offset by unfavourable merchant power prices in Alberta.	13
Gas: Lower due to lower realized power prices in Alberta, an increase in the carbon price in Canada, and higher OM&A driven by higher maintenance costs at the South Hedland facility, partially offset by higher volume of favourable hedging positions settled, positive contribution from the Heartland gas facilities and lower capacity payments.	(25)
Energy Transition: Higher due to lower fuel and purchased power costs, partially offset by increased economic dispatch due to lower market prices.	2
Energy Marketing: Higher due to favourable market volatility and the timing of realized settled trades during 2024 compared to the same period in 2023.	13
Corporate: Lower due to higher spend to support strategic and growth initiatives.	(8)
Adjusted EBITDA[(1)] for the three months ended Dec. 31, 2024	**285**

(1) Adjusted EBITDA is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

FCF for the three months ended Dec. 31, 2024, decreased by $73 million, or 60 per cent, compared to the same period in 2023.

	Three months ended Dec. 31
FCF for the three months ended Dec. 31, 2023	121
Lower adjusted EBITDA due to the items noted above.	(4)
Higher net interest expense[(1)] due to lower capitalized interest as a result of capital projects being completed in the first half of 2024 and lower interest income due to lower cash balances in 2024.	(23)
Higher current income tax expense due to the full utilization of Canadian non-capital loss carryforwards in 2023, partially offset by a higher loss before income taxes in the current period compared to the same period in 2023.	(25)
Lower sustaining capital due to lower planned maintenance at the Alberta gas facilities, partially offset by higher planned maintenance at the Sarnia cogeneration facility and Alberta hydro facilities.	7
Higher dividends paid on preferred shares.	(1)
Lower distributions paid to subsidiaries' non-controlling interests due to lower TA Cogen net earnings.	13
Higher provisions accrued in the current year compared to the prior year resulting in higher FCF.	3
Higher realized foreign exchange losses compared to realized foreign exchange gains in the comparative period.	(29)
Other[(2)]	(14)
FCF[(2)(3)] for the three months ended Dec. 31, 2024	**48**

(1) Net interest expense includes interest expense less interest income and excludes non-cash items ike financing amortization and accretion.
(2) Refer to the Reconciliation of Cash Flow from Operations to FFO and FCF section tables in this MD&A for more details.
(3) FCF is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Alberta Electricity Portfolio

The following table provides information for the Company's Alberta electricity portfolio for the three months ended Dec. 31:

	2024					2023				
Three months ended Dec. 31	Hydro	Wind & Solar	Gas	Energy Transition	Total	Hydro	Wind & Solar	Gas	Energy Transition	Total
Gross installed capacity (MW)	834	764	3,650	—	5,248	834	766	1,960	—	3,560
Total production[1] (GWh)	367	619	2,164	—	3,150	278	745	1,966	—	2,989
Contract production (GWh)	—	257	837	—	1,094	—	353	438	—	791
Merchant production (GWh)	367	362	1,327	—	2,056	278	391	1,528	—	2,197
Purchased power (GWh)	—	—	(286)	—	(286)	—	—	(50)	—	(50)
Hedged production (GWh)	205	44	2,388		2,637	58	82	1,684	—	1,824
Production contracted or hedged (%)	56%	49%	149%	—%	118%	21%	58%	108%	—%	87%
Hedged production as a percentage of gross installed capacity (%)	11%	3%	30%	—%	23%	3%	5%	39%	—%	23%
Revenues[2] ($)	72	24	235	1	332	71	38	221	1	331
Fuel ($)	1	3	86	1	91	3	5	76	—	84
Purchased power ($)	1	1	14	—	16	2	—	5	—	7
Carbon compliance[3] ($)	—	—	34	—	34	—	—	25	—	25
Gross margin[2] ($)	70	20	101	—	191	66	33	115	1	215

(1) Total production includes contract production and merchant production.

(2) Revenues have been adjusted to exclude the impact of unrealized mark-to-market gains or losses and to include realized gains and losses on closed exchange positions. Alberta Hydro revenues for the three months ended Dec. 31, 2024 exclude the impact of Brazeau penalties.

(3) The intercompany sales of emission credits from the Hydro segment to the Gas segment is eliminated on consolidation in the Corporate segment. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Total production for the Alberta portfolio for the three months ended Dec. 31, 2024, was 3,150 GWh, compared to 2,989 GWh for the same period in 2023. The increase of 161 GWh, or five per cent, was primarily due to:

- Higher production from the Alberta Gas assets due to the Heartland acquisition;
- Higher production from the Alberta Hydro Assets due to significant water conservation during the fourth quarter of 2023; partially offset by
- Higher economic dispatch for the Alberta gas facilities; and
- Lower production in the Wind and Solar segment due to lower wind resource.

Hedged production for the Alberta portfolio for the three months ended Dec. 31, 2024, increased compared to the same period in 2023. In anticipation of the risk of lower prices in 2024, the Company deployed a defensive strategy to increase financial hedges for the merchant portfolio at attractive margins. Realized gains and losses on financial hedges are included in revenues in the table above.

Gross margin for the Alberta portfolio for the three months ended Dec. 31, 2024, was $191 million, compared to $215 million in 2023. The decrease of $24 million, or eleven per cent, was primarily due to:

- Lower Alberta spot power prices;
- Higher carbon compliance costs due to increase in the carbon price from $65 per tonne in 2023 to $80 per tonne in 2024; and
- Higher purchased power due to the contractual requirement to fulfill physical power trades; partially offset by
- Higher gains realized on financial hedges settled in the period.

The following table provides information for the Company's Alberta electricity portfolio for the three months ended Dec. 31:

Three months ended Dec. 31	2024	2023
Alberta Market		
Spot power price average per MWh	**52**	82
Natural gas price (AECO) per GJ	**1.42**	2.19
Carbon compliance price per tonne	**80**	65
Alberta Portfolio Results		
Realized merchant power price per MWh[1]	**110**	117
Hydro energy spot power price per MWh	**78**	107
Hydro ancillary services price per MWh	**39**	37
Wind energy spot power price per MWh	**26**	49
Gas spot power price per MWh	**75**	101
Hedged power price average per MWh[2]	**80**	90
Hedged volume (GWh)	**2,637**	1,824
Fuel cost per MWh[3]	**42**	43
Carbon compliance cost per MWh[4]	**16**	13

(1) Rea ized merchant power price for the Alberta electricity portfolio is the average price realized as a result of the Company's merchant power sales and portfolio optimization activities (excluding assets under long-term contract and ancillary revenues) divided by total merchant GWh produced.

(2) Hedged power price average per MWh is calculated as the average sales price for all hedges and direct customer sales during the reporting period.

(3) Fuel cost per MWh is calculated on production from carbon-emitting generation in the Gas and Energy Transition segments.

(4) Carbon compliance cost per MWh is calculated on production from carbon-emitting generation, as well as power purchased, in the Gas and Energy Transition segments.

The average spot power price per MWh for the Alberta portfolio for the three months ended Dec. 31, 2024, decreased from $82 per MWh in 2023 to $52 per MWh in 2024, primarily due to:

- Higher generation from the addition of increased supply of new renewables and combined-cycle gas facilities into the market compared to the prior period; and
- Lower natural gas prices.

The realized merchant power price per MWh of production for the Alberta portfolio for the three months ended Dec. 31, 2024, although significantly higher than average spot power prices during the year, decreased by $7 per MWh compared to the same period in 2023, primarily due to:

- Lower average spot power prices as explained above; and
- Lower hedge prices compared to the prior year.

Fuel cost per MWh for the three months ended Dec. 31, 2024, decreased by $1 per MWh, compared to the same period in 2023, primarily due to lower natural gas prices.

Carbon compliance cost per MWh of production for the Alberta portfolio for the three months ended Dec. 31, 2024, increased by $3 per MWh, compared to 2023, primarily due to the carbon compliance price increase from $65 per tonne in 2023 to $80 per tonne in 2024.

Selected Quarterly Information

Our results are seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are often incurred in the spring and fall when electricity prices are expected to be lower, and electricity prices generally increase in the peak winter and summer months in our main markets due to increased heating and cooling loads. Margins are also typically impacted in the second quarter due to the volume of hydro production resulting from spring runoff and rainfall in the Pacific Northwest, which impacts production at Centralia. Typically, hydroelectric facilities generate most of their electricity and revenues during the spring months when melting snow starts feeding watersheds and rivers. Inversely, wind speeds are historically greater during the cold winter months and lower in the warm summer months.

	Q1 2024	Q2 2024	Q3 2024	Q4 2024
Revenues	947	582	638	**678**
Carbon compliance	40	(8)	41	**39**
OM&A	134	144	143	**234**
Depreciation and amortization	124	131	133	**143**
Earnings (loss) before income taxes	267	94	9	**(51)**
Net earnings (loss) attributable to common shareholders	222	56	(36)	**(65)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted[(1)]	0.72	0.18	(0.12)	**(0.22)**
Cash flow from operating activities	244	108	229	**215**

	Q1 2023	Q2 2023	Q3 2023	Q4 2023
Revenues	1,089	625	1,017	624
Carbon compliance	32	25	28	27
OM&A	124	134	131	150
Depreciation and amortization	176	173	140	132
Earnings (loss) before income taxes	383	79	453	(35)
Net earnings (loss) attributable to common shareholders	294	62	372	(84)
Net earnings (loss) per share attributable to common shareholders, basic and diluted[(1)]	1.10	0.23	1.41	(0.27)
Cash flow from operating activities	462	11	681	310

(1) Basic and diluted earnings (loss) per share attributable to common shareholders is calculated in each period using the basic and diluted weighted average common shares outstanding during the period, respectively. As a result, the sum of the earnings (loss) per share for the four quarters making up the calendar year may sometimes differ from the annual earnings (loss) per share.

Operating results have been impacted by the following events:

- Acquisition of Heartland on Dec. 4, 2024. Refer to the Significant and Subsequent events section of this MD&A for more details; and
- Commissioning of the Garden Plain wind facility in the third quarter of 2023, the Northern Goldfields solar facilities in the fourth quarter of 2023, the White Rock West wind facility and the Mount Keith 132kV expansion in the first quarter of 2024 and the White Rock East and Horizon Hill wind facilities in the second quarter of 2024.

In addition to the items described above, revenues have been impacted by:

- Higher production in each quarter of 2024, compared to the same periods in the prior year;
- The effects of unrealized mark-to-market gains and losses from hedging and derivative positions; and
- Lower realized pricing in each quarter of 2024, compared to the same periods in the prior years impacted by additions of new natural gas, wind and solar supply in the Alberta market in 2024.

Carbon compliance costs have been impacted by:

- Higher costs of carbon per tonne. In 2024, the cost of carbon was $80 per tonne as compared to $65 per tonne in 2023; and
- In the second quarter of 2024, carbon compliance costs were reduced by using internally generated and externally purchased emission credits to settle a portion of the 2023 GHG obligation.

OM&A has been impacted by:

- Higher costs stemming from planning and design work on a planned upgrade to our ERP system in all quarters of 2024;
- Higher spend to support strategic and growth initiatives in all quarters of 2024 compared to same period in prior year;
- Return to service of Kent Hills wind facilities and the addition of Horizon Hill and White Rock wind facilities.
- In the fourth quarter of 2024 Heartland acquisition-related transaction and restructuring costs, mainly comprising severance, legal and consultant fees; and
- In the fourth quarter of 2024 penalties assessed by the Alberta Market Surveillance Administrator for self-reported contraventions pertaining to Hydro ancillary services provided during 2021 and 2022.

Depreciation has been impacted by:

- Revisions in the useful lives of certain facilities that occurred in the third quarters of 2023 and 2024, partially offset by
- An increase in depreciation due to the addition of White Rock wind facilities in the first quarter of 2024, Horizon Hill wind facilities in the second quarter of 2024.

Higher asset impairment charges due to:

- Development projects that are no longer proceeding in all four quarters of 2024;
- Increase in decommissioning provisions for retired assets due to changes in estimated cash flows in the third quarter of 2023 and 2024; and
- changes in expected timing of restoration expenditures occurring, recognized in the third quarter of 2023 and the third and fourth quarters of 2024.

Earnings (loss) before income taxes has been impacted by the following:

- The items described above; and
- Higher interest expense due to lower capitalized interest during 2024 as compared to 2023 resulting from lower capital activity in 2024 compared to 2023.

Net earnings (loss) attributable to common shareholders has been impacted by fluctuations in current and deferred tax expense with earnings before tax across the quarters.

Cash flow from operating activities has been impacted by the following:

- The items described above;
- Unfavourable changes in non-cash operating working capital balances in the last four quarters of 2024, compared to the same periods in the prior year due to unfavourable changes in accounts payable and accrued liabilities due to lower capital spend and lower cost accruals, partially offset by lower collateral provided due to lower market volatility;
- Higher unrealized foreign exchange gains in the last four quarters of 2024 compared to the same periods in 2023; and
- Higher provisions and other non-cash items.

Strategic Priorities

The Company remains focused on investing in electricity solutions that meet the evolving needs of customers and communities. We take a balanced, prudent and disciplined approach to capital allocation, ensuring long-term value creation for shareholders. Our strategy prioritizes generating meaningful, risk-adjusted returns by optimizing our legacy thermal assets, operating our diverse fleet of renewable facilities, our exceptional marketing and trading capabilities, and expanding our generating portfolio through the addition of contracted clean energy assets and selective gas assets. Given our skill set, competitive advantages and market positioning, we are well-positioned to capture significant opportunities in our core markets of Canada, the United States and Western Australia.

The Company continues to make strong progress on key strategic priorities, ensuring the business remains resilient, growth-focused and aligned with the evolving energy landscape.

Optimize Alberta Portfolio

In Alberta, the Company continues to proactively deploy hedging strategies, to mitigate the impact of lower merchant power prices, along with optimization activities. The acquisition of Heartland Generation has significantly strengthened our Alberta portfolio, adding 1,747 MW of flexible capacity, including contracted cogeneration, peaking generation and transmission capacity. Of note, the acquisition added 290 MW of peaking gas capacity, which will be optimized within our larger portfolio to address increasing intermittency in Alberta.

The Company is maximizing the value of its hydro fleet by enhancing its operational capabilities and flexibility. We are also advancing initiatives to maximize the value of our existing thermal assets and meet the growing demand for affordable and reliable power.

Execute Growth Plan

In 2024, significant progress was made on growth initiatives. Early in the year we successfully completed our two Oklahoma wind facilities: the 302 MW White Rock wind facilities and the 202 MW Horizon Hill wind facility. We also achieved commercial operations for our Mount Keith Transmission Expansion project. These additions, along with the fully rehabilitated Kent Hills facilities are expected to contribute over $175 million in EBITDA annually.

Our growth plan is guided by a technology-agnostic approach, focusing on our core operating jurisdictions and clear target customer segments within them.

Realize the Value of Legacy Generating Facilities

The Company is seeing considerable opportunities to support the energy transition with sophisticated, reliable and affordable power solutions in our core operating jurisdictions. Particularly, at our legacy thermal sites in Alberta and Washington State, where we are actively pursuing accretive opportunities with existing and prospective customers. We believe that these sites hold significant value and provide unique advantages to customers.

Maintain Financial Strength and Capital Discipline

The Company maintains a strong financial position, with $1.6 billion in liquidity as of Dec. 31, 2024, and a disciplined approach to capital allocation. The Company balances investments in growth, debt repayments and returns to shareholders through share repurchases and dividend payments. Reflecting confidence in the business, the annual common share dividend was increased by eight per cent to $0.26 per share, our sixth consecutive dividend increase, effective July 1, 2025. The Company also announced an ongoing commitment to its share repurchase plan, allowing the Company to repurchase up to $100 million in common shares. Together, these actions represent a return of up to 35 per cent of the midpoint of 2025 free cash flow guidance to shareholders.

Define Next Generation of Power Solutions

The Company has been at the forefront of innovation in the power-generation sector since the early 1900s when we developed our first hydro assets. We continue to make progress on our identification of the next generation of energy solutions that will be needed to power our customers' needs in an efficient, reliable and affordable manner. Refer to the Enabling Innovation and Technology Adoption section of the MD&A for further discussion.

Lead in ESG and Market Policy Development

The Company is an active participant in policy development in all key markets in which we operate. Most notably, we are actively engaging with the Government of Alberta and the Alberta Electric System Operator on Alberta's restructured energy market, which is intended to deliver the objectives of reliability, affordability, and decarbonization by 2050 for the province. TransAlta is committed to actively engaging in the AESO's consultation process, to support the development of an investable market structure that can responsibly achieve a sustainable grid in a manner that ensures reliability and affordability for Albertans.

Growth

Throughout 2024 we refined our development pipeline to reflect our views on changes in regulation, interconnection timelines and with a focus on maximizing returns and meeting the evolving needs of our customers. We also incorporated additional redevelopment opportunities at our legacy thermal facilities. We will continue to take a disciplined approach to evaluating project economics. Our pipeline includes 280 MW of advanced-stage development projects along with 3,330 to 5,230 MW of projects in earlier stages of development. We are focused primarily on redevelopment opportunities at our legacy sites in addition to evaluating greenfield and merger and acquisition prospects in Alberta, Western Australia and the western United States.

Advanced-Stage Development

These projects have detailed engineering, advanced positions in the interconnection queue and/or are progressing offtake opportunities. Projects in advanced-stage development do not have final approval from the Board of Directors at time of reporting.

The following table shows the pipeline of future growth projects in advanced-stage development:

Project	Type	Region	Target investment date	MW
Tempest	Wind	Alberta	On hold	100
WaterCharger	Battery Storage	Alberta	On hold	180

Early-Stage Development

These projects are in the early stages and may or may not move ahead. Generally, these projects will have:

- Collected meteorological data;
- Begun securing land control;
- Started environmental studies;
- Confirmed appropriate access to transmission; and
- Started preliminary permitting and other regulatory approval processes.

The following table shows the pipeline of future growth projects currently under early-stage development:

Project	Type	Region	Potential investment date[1]	MW
Canada				
New Brunswick Battery	Battery	New Brunswick	2027+	10
SunHills Solar	Solar	Alberta	2027+	170
Tent Mountain Pumped Storage[2]	Hydro	Alberta	2029	192
Provost	Wind	Alberta	2027+	170
Red Rock	Wind	Alberta	2027+	100
Antelope Coulee	Wind	Saskatchewan	2027+	200
Other Canadian Opportunities	Wind	Various	2026+	374
Brazeau Pumped Hydro	Hydro	Alberta	TBD	300-900
Alberta Thermal Redevelopment[3]	Various	Alberta	2027+	400-1200
		Total		**1,916 - 3,316**
United States				
Square Top	Solar	Oklahoma	2026	195
Old Town	Wind	Illinois	2026	185
Trapper Valley	Wind	Wyoming	2027+	225
Other U.S. opportunities	Wind	Various	2026+	144
Centralia site redevelopment[3]	Various	Washington	2025+	500-1000
		Total		**1,249 - 1,749**
Australia				
Boodarie Solar	Solar	Western Australia	2025	50
Other Australian opportunities	Gas, Solar, Transmission	Western Australia	2025+	115
		Total		**165**
Canada, United States and Australia		**Total**		**3,330 - 5,230**

(1) Potential investment date is to be determined (TBD).

(2) This represents the Company's 60 per cent interest in Tent Mountain Renewable Energy Complex.

(3) The Company is currently evaluating redevelopment opportunities at these brownfield sites.

Projects under Construction

Projects under construction will be financed through existing liquidity in the near term.

We will continue to explore permanent financing solutions on an asset-by-asset basis. We are continually monitoring the timing and costs of our projects under construction.

The following projects have been approved by the Board of Directors, have executed PPAs and are currently under construction or in the process of being commissioned:

				Total project (millions)					
Project	Type	Region	MW	Estimated spend	Spent to date	Target completion date	PPA Term (years)	Average annual EBITDA[1] range	Status
Western Australia									
Mount Keith West network upgrade	Transmission	WA	n/a	AU$37 — AU$40	AU$19	Q4 2025	14	AU$6 - AU$7	• Engineering completed • Site works commenced • On track to be completed on schedule
Total[2]			**n/a**	**$34 — $36**	**$17**			**$6 - $7**	

(1) This item is not defined and has no standardized meaning under IFRS and is forward-looking. It may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion.

(2) Total expected spending and average annual EBITDA were converted using a Canadian dollar forward exchange rate for 2024. Spend to date was converted using the period-end closing rate.

Financial Position

The following table highlights significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2023, to Dec. 31, 2024:

	Dec. 31, 2024	Dec. 31, 2023	Increase/(decrease)
Assets			
Current assets			
Cash and cash equivalents	**337**	348	(11)
Trade and other receivables	**767**	807	(40)
Risk management assets	**318**	151	167
Assets held for sale	**80**	—	80
Other current assets[1]	**271**	274	(3)
Total current assets	**1,773**	1,580	193
Non-current assets			
Risk management assets	**93**	52	41
Investments	**159**	138	21
Property, plant and equipment, net	**6,020**	5,714	306
Intangible assets, net	**281**	223	58
Deferred income tax assets	**52**	21	31
Goodwill	**517**	464	53
Long-term portion of finance lease receivable	**305**	171	134
Other non-current assets[2]	**299**	296	3
Total non-current assets	**7,726**	7,079	647
Total assets	**9,499**	8,659	840
Liabilities			
Current liabilities			
Accounts payable, accrued liabilities and other current liabilities	**756**	809	(53)
Risk management liabilities	**277**	314	(37)
Decommissioning and other provisions (current)	**83**	35	48
Credit facilities, long-term debt and lease liabilities	**572**	532	40
Exchangeable securities	**750**	—	750
Contingent consideration payable	**81**	—	81
Other current liabilities[3]	**50**	52	(2)
Total current liabilities	**2,569**	1,742	827
Non-current liabilities			
Credit facilities, long-term debt and lease liabilities	**3,236**	2,934	302
Exchangeable securities	**—**	744	(744)
Decommissioning and other provisions (long-term)	**850**	654	196
Risk management liabilities (long-term)	**305**	274	31
Defined benefit obligation and other long-term liabilities	**202**	251	(49)
Deferred income tax liabilities	**470**	386	84
Other non-current liabilities[4]	**24**	10	14
Total non-current liabilities	**5,087**	5,253	(166)
Total liabilities	**7,656**	6,995	661
Equity			
Equity attributable to shareholders	**1,746**	1,537	209
Non-controlling interests	**97**	127	(30)
Total equity	**1,843**	1,664	179
Total liabilities and equity	**9,499**	8,659	840

(1) Includes restricted cash, inventory and prepaid expenses and other.
(2) Includes right-of-use assets and other assets.
(3) Includes bank overdraft and dividends payable.
(4) Includes contract liabilities.

Significant changes in Company's Consolidated Statements of Financial Position were as follows:

On Dec. 4, 2024, the Company acquired Heartland. The Financial Position as at Dec. 31, 2024 includes the assets and liabilities of Heartland. Refer to note 4 of our consolidated financial statements for further details.

Working Capital

The deficit of current assets over current liabilities, including the current portion of long-term debt and lease liabilities, was $796 million as at Dec. 31, 2024 (Dec. 31, 2023 – deficit of current assets over current liabilities of $162 million). The deficit increased primarily as a result of the reclassification of the exchangeable securities to a current liability. The exchangeable securities are classified as current as their conversion option can be exercised at any time after Dec. 31, 2024 at Brookfield's option, although there is no obligation to deliver cash equivalent resources and the holder cannot call for repayment. Refer to the Accounting Changes section of this MD&A for more details.

Current assets increased by $193 million to $1,773 million as at Dec. 31, 2024, from $1,580 million as at Dec. 31, 2023, primarily due to:

- Higher risk management assets mainly due to changes in market pricing across multiple markets as well as higher price forecasts;
- Addition of assets held for sale for the Planned Divestitures (refer to Significant and Subsequent events section); partially offset by
- Lower trade receivables, mainly due to timing of cash receipts and lower collateral provided in the Energy Marketing segment due to favourable changes in market prices, offset by an increase in trade and other receivables due to Heartland acquisition; and
- Lower cash and cash equivalents mainly due to lower cash flow from operating activities.

Current liabilities increased by $827 million from $1,742 million as at Dec. 31, 2023, to $2,569 million as at Dec. 31, 2024, mainly due to:

- The exchangeable securities being classified as current as described above;
- Contingent consideration payable related to the Planned Divestitures (refer to the Significant and Subsequent events section); and
- Higher current portion of decommissioning and other provisions due to the addition of balances from Heartland;
- Higher current portion of credit facilities, long-term debt and lease liabilities mainly due to additions of balances from Heartland; partially offset by
- Lower accounts payable, accrued liabilities and other current liabilities mainly due to lower cost accruals and lower capital spend, partially offset by the additions of accounts payable balances from Heartland acquisition and higher current income taxes payable; and
- Lower risk management liabilities due to changes in market pricing across multiple prices and contract settlements.

Non-Current Assets

Non-current assets as at Dec. 31, 2024, were $7,726 million, an increase of $647 million from $7,079 million as at Dec. 31, 2023, primarily due to:

- Higher property, plant and equipment (PP&E) resulting from $413 million of additions from Heartland recognized at acquisition and capital additions of $311 million mainly related to the construction of growth projects and planned major maintenance activities. The increase in PP&E additions was partially offset by depreciation of $516 million;
- Higher finance lease receivable related to the additions from Heartland and the Mount Keith 132kV finance lease receivable;
- Higher deferred income tax asset due to an increase in deductible temporary differences arising from the Heartland acquisition;
- Higher risk management assets due to favourable changes in market prices across multiple markets and addition of risk management assets from Heartland;
- Higher goodwill balance due to goodwill arising on Heartland acquisition;
- Higher intangibles mainly due to the addition of power sale contracts from Heartland; and
- Higher investments balance resulting from contributions and equity income from equity-accounted investments.

Non-Current Liabilities

Non-current liabilities as at Dec. 31, 2024 were $5,087 million, a decrease of $166 million from $5,253 million as at Dec. 31, 2023, mainly due to:

- The exchangeable securities being classified as current liabilities;
- Lower defined benefit obligations and other long-term liabilities mainly due to a decrease in retail power contract liabilities resulting from amortization based on volumes delivered; partially offset by
- Increase in credit facilities, long-term debt and lease liabilities due to the addition of Heartland credit facilities and an increase in the cash drawings under the syndicated credit facility;

- Increase in decommissioning and other provisions due to additions of generating facilities from Heartland acquisition, revisions in discounts rates and estimated decommissioning costs and commissioning of Horizon Hill and White Rock wind facilities;
- Higher deferred income tax liabilities due to an increase in temporary taxable differences arising from the Heartland acquisition; and
- Higher risk management liabilities due to forward price changes and volatility in market pricing across multiple markets.

Total Equity

As at Dec. 31, 2024, the increase in total equity of $179 million was due to:

- Net earnings of $239 million; and
- Net gains on derivatives from cash flow hedges of $194 million; partially offset by
- Share repurchases under the NCIB of $143 million;
- Dividends declared on common and preferred shares of $123 million; and
- Distributions to non-controlling interests of $40 million.

Financial Capital

The Company is focused on maintaining a strong balance sheet and financial position to ensure access to sufficient financial capital. Credit ratings provide information relating to the Company's financing costs, liquidity and operations, and affect the Company's ability to obtain short and long-term financing and/or the cost of such financing. Maintaining a strong balance sheet also allows the Company to enter into contracts with a variety of counterparties on terms and prices that are favourable to the Company's financial results and provide TransAlta with better access to capital markets through commodity and credit cycles.

In 2024, Moody's reaffirmed the Company's long-term rating of Ba1 with a stable outlook. Morningstar DBRS reaffirmed the Company's issuer rating and unsecured debt/medium-term notes rating of BBB (low) and the Company's preferred shares rating of Pfd-3 (low), all with a stable outlook. In addition, S&P Global Ratings reaffirmed the Company's senior unsecured debt rating and issuer credit rating of BB+ with a stable outlook. Risks associated with our credit ratings are discussed in the Governance and Risk Management section of this MD&A.

Capital Structure

Our capital structure consists of the following components as shown below:

	2024		2023		2022	
	$	%	$	%	$	%
Net senior unsecured debt						
Recourse debt - CAD debentures	**251**	**4**	251	5	251	5
Recourse debt - U.S. senior notes	**995**	**16**	911	17	934	18
Credit facilities	**543**	**9**	397	7	428	9
Other	**—**	**—**	—	—	1	—
Less: cash and cash equivalents[1]	**(336)**	**(6)**	(345)	(6)	(1,118)	(21)
Less: other cash and liquid assets[2]	**(7)**	**—**	5	—	(3)	—
Net senior unsecured debt	**1,446**	**23**	1,219	23	493	11
Other debt liabilities						
Exchangeable debentures	**350**	**6**	344	6	339	6
Non-recourse debt						
TAPC Holdings LP bond	**75**	**1**	85	1	94	2
Pingston bond	**39**	**1**	39	1	45	1
Melancthon Wolfe Wind bond	**133**	**2**	168	3	202	4
New Richmond Wind bond	**93**	**2**	103	2	112	2
Kent Hills Wind bond	**179**	**3**	193	3	206	4
Windrise Wind bond	**157**	**3**	164	3	170	3
South Hedland non-recourse debt	**675**	**11**	691	13	711	14
Heartland term facility	**224**	**4**	—	—	—	—
OCP Bond	**192**	**3**	217	4	241	4
OCP LP restricted cash[3]	**(17)**	**—**	(17)	—	(17)	—
U.S. tax equity financing	**101**	**1**	104	1	123	2
Lease liabilities	**151**	**2**	143	3	135	2
Total consolidated net debt[4][5][6]	**3,798**	**62**	3,453	63	2,854	55
Exchangeable preferred securities[6]	**400**	**7**	400	7	400	7
Equity attributable to shareholders						
Common shares	**3,179**	**53**	3,285	60	2,863	54
Preferred shares	**942**	**16**	942	17	942	18
Contributed surplus, deficit and accumulated other comprehensive loss	**(2,375)**	**(40)**	(2,690)	(49)	(2,695)	(51)
Non-controlling interests	**97**	**2**	127	2	879	17
Total capital	**6,041**	**100**	5,517	100	5,243	100

(1) Cash and cash equivalents is net of bank overdraft.

(2) Includes the fair value of economic and designated hedging instruments on debt, as the carrying value of the related debt is impacted by changes in foreign exchange rates.

(3) Principal portion of the TransAlta OCP LP restricted cash related to the TransAlta OCP LP bonds as this cash is restricted specifically to repay outstanding debt.

(4) These items are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion, including reconciliations to measures calculated in accordance with IFRS.

(5) The tax equity financing for the Skookumchuck wind faci ity, an equity-accounted joint venture, is not represented in these amounts.

(6) The total consolidated net debt excludes the exchangeable preferred securities as they are considered equity with dividend payments for credit purposes.

We have enhanced liquidity and shareholder value through the following:

2024

- Renewed the $400 million Term Facility with the maturity extended by one year to September 2025;
- Extended the $1.9 billion syndicated credit facility and $240 million bilateral credit facilities by one year to June 2028 and June 2026, respectively;
- Purchased and cancelled 13,467,400 common shares at an average price of $10.59 per share through our NCIB program, for a total cost of $143 million; and
- Assumed new credit facilities and letter of credit facilities as part of the Heartland acquisition.

2023

- Extended the committed syndicated credit facility by one year to June 30, 2027, and the committed bilateral credit facilities by one year to June 30, 2025;
- Refinanced the $45 million Pingston non-recourse bond due in 2023 with a non-recourse bond for approximately $39 million, with a fixed interest rate of 6.145 per cent per annum, payable semi-annually, and maturing on May 8, 2043; and
- Purchased and cancelled 7,537,500 common shares at an average price of $11.49 per share through our NCIB program, for a total cost of $87 million.

2022

- Issued US$400 million Senior Green Bonds, with a fixed coupon rate of 7.75 per cent per annum (effective interest rate of 5.98 per cent), due on Nov. 15, 2029;
- Repaid the US$400 million 4.50 per cent unsecured senior notes due 2022;
- Extended the committed syndicated credit facilities by one year to June 30, 2026, and the committed bilateral credit facilities by one year to June 30, 2024;
- Closed a two-year floating rate Term Facility with our banking syndicate for $400 million with a maturity date of Sept. 7, 2024. The Term Facility has interest rates that vary depending on the option selected (e.g., Canadian prime and bankers' acceptances); and
- Purchased and cancelled 4,342,300 common shares at an average price of $12.48 per share through our NCIB program, for a total cost of $54 million.

Credit Facilities

The Company's credit facilities are summarized in the table below:

As at Dec. 31, 2024		Utilized			
Credit facilities	**Facility size**	**Outstanding letters of credit[1]**	**Cash drawings**	**Available capacity**	**Maturity date**
Committed					
Syndicated credit facility	1,950	456	145	1,349	Q2 2028
Bilateral credit facilities	240	161	—	79	Q2 2026
Term Facility	400	—	400	—	Q3 2025
Heartland Credit Facilities	276	14	224	38	Q4 2027
Heartland EDC letter of credit facility	50	14	—	36	Q1 2025
Total Committed	**2,916**	**645**	**769**	**1,502**	
Non-Committed					
Demand facilities	400	220	—	180	N/A
Total Non-Committed	**400**	**220**	**—**	**180**	

(1) TransAlta has obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, pension plan obligations, construction projects and purchase obligations. Letters of credit drawn against the non-committed facilities reduce available capacity under the committed syndicated credit facilities.

In the second quarter of 2024, the $400 million Term Facility was renewed with the maturity extended by one year to September 2025. The $1,900 syndicated credit facility and $240 million bilateral credit facilities were also extended by one year to June 2028 and June 2026, respectively.

As part of the Heartland acquisition on Dec. 4, 2024, the Company assumed a $232 million drawn term facility and $25 million revolving facility with a syndicate of banks, (collectively Heartland Credit Facilities). At Dec. 31, 2024 the drawn term facility was $224 million. The $25 million revolving facility is undrawn and available for working capital and general corporate purposes. The maturity date for the Heartland Credit Facilities is Dec. 22, 2027. The Heartland Credit Facilities also include a $27 million debt service reserve letter of credit facility.

As part of the Heartland acquisition, the Company has access to a $50 million unsecured letter of credit facility with two Canadian banks, which is supported by a performance security guarantee from Export Development Canada (EDC).

The Heartland Credit Facilities are not subject to any maintenance or financial covenants but do contain certain covenants that limit Heartland's ability to, among other things, incur additional indebtedness, create or permit liens to exist, make certain acquisitions or dispositions, make distributions and enter into certain hedging agreements.

Non-Recourse Debt and Other

The Melancthon Wolfe Wind LP, Pingston Power Inc., TAPC Holdings LP, New Richmond Wind LP, Kent Hills Wind LP, TEC Hedland Pty Ltd. and Windrise Wind LP non-recourse bonds, the TransAlta OCP LP bond, and Heartland Credit Facilities are subject to customary financing conditions and covenants that may restrict the Company's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt-service coverage ratio prior to distribution, which was met by these entities in the fourth quarter of 2024, with the exception of Kent Hills Wind LP. The funds in the Kent Hills Wind entity that have accumulated since the fourth quarter test will remain there until the next debt-service coverage ratio is calculated in the first quarter of 2025. At Dec. 31, 2024, $117 million (Dec. 31, 2023 – $79 million) of cash was subject to these financial restrictions.

At Dec. 31, 2024, $5 million (AU$6 million) of funds held by TEC Hedland Pty Ltd. are not able to be accessed by other corporate entities as the funds must be solely used by the project entities for the purpose of paying major maintenance costs.

Additionally, certain non-recourse bonds require that reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit.

Between 2025 and 2027, the Company has a total of $1,066 million of scheduled debt repayments, including the $400 million maturity of the Term Facility, with the balance of $666 million related to scheduled non-recourse debt and tax equity repayments. The $750 million of exchangeable securities are exchangeable after Dec. 31, 2024.

U.S. Tax Equity Financing and Production Tax Credits

The Company owns equity interests in wind facilities that are eligible for tax incentives available for renewable energy facilities in the U.S. Current U.S., tax law allows qualified wind energy projects to receive production tax credits (PTCs) that are earned for each MWh of generation during the first 10 years of the project's operation. To monetize tax incentives, the Company has partnered with Tax Equity Investors (TEIs) who invest in these facilities in exchange for a share of the tax incentives and cash. TransAlta accounts for the TEIs' interest as long-term debt, where cash distributions and allocations of tax incentives to the TEIs primarily reduce the long-term debt balance. Upon the TEIs achieving an agreed-upon after-tax investment return, the project flip point occurs (Flip Point). Prior to achieving the Flip Point, the TEIs are allocated substantially all of the taxable attributes including PTCs produced and a proportion of cash. After the Flip Point has been reached, the Company retains substantially all of the cash and the taxable income (losses) generated by the facility.

In 2023, U.S. tax laws were amended to allow entities to monetize certain clean energy tax credits, including PTCs, by transferring (selling) them to third-party taxpayers, in exchange for cash consideration.

The following table outlines information regarding the Company's tax equity financing arrangements with PTC eligibility:

Facility	Commercial operation date	Expected Flip Point	Initial TEI investment ($US)	Expected annual PTC ($US)	TEI allocation of cash distributions (pre-Flip Point) Undiscounted[1] ($US)	TEI allocation of taxable income and PTCs (pre-Flip Point)
Lakeswind	2014	2027	45	—	7	99%
Big Level and Antrim	2019	2029	126	10	41	99%
Skookumchuck[2]	2020	2030	121	11	17	99%
North Carolina Solar	2021	2028	64	N/A	7	N/A

(1) Cumulative expected cash distributions from Dec. 31, 2024 to the expected Flip Point.

(2) The Company has a 49 per cent interest in the Skookumchuck wind facility, which is treated as an equity investment under IFRS and our proportionate share of the net earnings is reflected as equity income on the statement of earnings under IFRS.

Returns to Providers of Capital

Interest Income and Interest Expense

Interest income and the components of interest expense are shown below:

Year ended Dec. 31	2024	2023	2022
Interest income	**30**	59	24
Interest on debt	**197**	203	164
Interest on exchangeable debentures	**31**	29	29
Interest on exchangeable preferred shares	**28**	28	28
Capitalized interest	**(16)**	(57)	(16)
Interest on lease liabilities	**10**	9	7
Credit facility fees, bank charges and other interest	**21**	21	27
Tax shield on tax equity financing	**3**	—	(2)
Accretion of provisions	**50**	48	49
Interest expense	**324**	281	286

Interest income was lower due to lower average cash balances and lower interest rates. Interest expense was higher than in 2023, primarily due to lower capitalized interest resulting from lower construction activity in 2024 compared to 2023.

Share Capital

The following tables outline the common and preferred shares issued and outstanding:

	Number of shares (millions)		
As at	**Feb. 19, 2025**	**Dec. 31, 2024**	**Dec. 31, 2023**
Common shares issued and outstanding, end of period	**297.6**	**297.5**	306.9
Preferred shares			
Series A	**9.6**	**9.6**	9.6
Series B	**2.4**	**2.4**	2.4
Series C	**10.0**	**10.0**	10.0
Series D	**1.0**	**1.0**	1.0
Series E	**9.0**	**9.0**	9.0
Series G	**6.6**	**6.6**	6.6
Preferred shares issued and outstanding in equity	**38.6**	**38.6**	38.6
Series I - exchangeable securities[1]	**0.4**	**0.4**	0.4
Preferred shares issued and outstanding	**39.0**	**39.0**	39.0

(1) Brookfield invested $400 million in consideration for redeemable, retractable, first preferred shares. For accounting purposes, these preferred shares are considered debt and disclosed as such in the consolidated financial statements.

Non-Controlling Interests

On Oct. 5, 2023, the Company acquired all of the outstanding common shares of TransAlta Renewables not already owned, directly or indirectly, by TransAlta and certain of its affiliates.

As at Dec. 31, 2024, the Company owned 50.01 per cent of TransAlta Cogeneration, LP (TA Cogen) (Dec. 31, 2023 – 50.01 per cent), which owns, operates or has an interest in three natural-gas-fired cogeneration facilities (Ottawa, Windsor and Fort Saskatchewan) and a natural-gas-fired facility (Sheerness). On Dec. 4, 2024, the Company acquired the remaining 50 per cent interest in Sheerness as part of the Heartland acquisition.

As at Dec. 31, 2024, the Company owned 83 per cent of Kent Hills Wind LP (Dec. 31, 2023 - 83 per cent), which owns and operates three wind facilities.

Since the Company owns a controlling interest in TA Cogen and Kent Hills Wind LP, we consolidated the entire earnings, assets and liabilities in relation to the subsidiaries.

Earnings, assets and liabilities of these subsidiaries, and of TransAlta Renewables prior to Oct. 5, 2023, were allocated to the other owners in proportion to their ownership interests. On Oct. 5, 2023, the Company acquired all of the outstanding common shares of TransAlta Renewables not already owned, directly or indirectly.

The reported net earnings attributable to non-controlling interests for the year ended Dec. 31, 2024, decreased by $91 million, compared to 2023, primarily as a result of lower TA Cogen net earnings attributable to non-controlling interests resulting from lower production and lower merchant pricing in the Alberta market and the cessation of distributions to TransAlta Renewables non-controlling interest.

Cash Flows

The following table highlights significant changes in the Consolidated Statements of Cash Flows for the year ended Dec. 31, 2024 and Dec. 31, 2023:

Year ended Dec. 31	2024	2023	2022
Cash and cash equivalents, beginning of year	**348**	1,134	947
Provided by (used in):			
Operating activities	**796**	1,464	877
Investing activities	**(520)**	(814)	(741)
Financing activities	**(291)**	(1,432)	45
Translation of foreign currency cash	**4**	(4)	6
Cash and cash equivalents, end of year	**337**	348	1,134

Cash Flow from Operating Activities

Cash from operating activities for the year ended Dec. 31, 2024, decreased compared with the same period in 2023, primarily due to the following:

	Year ended Dec. 31
Cash flow from operating activities for the year ended Dec. 31, 2023	1,464
Lower gross margin due to lower revenues, excluding the effect of unrealized losses from risk management activities, partially offset by lower fuel and purchased power.	(351)
Higher OM&A due to increased spending on planning and design of an ERP system upgrade, higher spending on strategic and growth initiatives, penalties assessed by the Alberta Market Surveillance Administrator for self-reported contraventions and Heartland acquisition-related transaction and restructuring costs.	(116)
Higher current income tax expense due to the full utilization of Canadian non-capital loss carryforwards in 2023, offset by lower earnings before income taxes in 2024.	(93)
Lower interest income due to lower cash balances and lower interest rates.	(29)
Higher interest expense on debt primary due to lower capitalized interest resulting from lower construction activity in 2024 compared to 2023.	(35)
Unfavourable change in non-cash operating working capital balances due to lower accounts payables and accrued liabilities, partially offset by lower collateral provided as a result of market price volatility.	(86)
Other non-cash items	42
Cash flow from operating activities for the year ended Dec. 31, 2024	**796**

Cash from operating activities for the year ended Dec. 31, 2023, increased compared with the same period in 2022, primarily due to the following:

	Year ended Dec. 31
Cash flow from operating activities for the year ended Dec. 31, 2022	877
Higher gross margin due to lower natural gas costs included in fuel and purchased power, partially offset by lower revenues net of unrealized gains and losses from risk management activities and higher carbon compliance costs.	127
Higher OM&A due to increased spending on strategic and growth initiatives, higher costs associated with the relocation of the Company's head office, and increased costs due to inflationary pressures.	(18)
Lower current income tax expense due to previously restricted non-capital loss carryforwards were utilized to offset taxable income.	15
Higher interest income due to higher cash balances and favourable interest rates.	35
Favourable change in non-cash operating working capital balances due to lower accounts receivable and collateral provided as a result of volatility in the market and market prices, partially offset by lower accounts payable and collateral received related to derivative instruments.	440
Other	(12)
Cash flow from operating activities for the year ended Dec. 31, 2023	**1,464**

Cash Flow Used in Investing Activities

Cash used in investing activities for the year ended Dec. 31, 2024, decreased compared with the same period in 2023, primarily due to the following:

	Year ended Dec. 31
Cash flow used in investing activities for the year ended Dec. 31, 2023	(814)
Cash paid for the acquisition of Heartland.	(217)
Lower additions to PP&E due to larger construction program in 2023 compared to 2024.	564
Lower proceeds on sale of PP&E due to the sale of equipment related to Sundance Unit 5 in 2023.	(25)
Unfavourable change in non-cash investing working capital balances due to lower capital accruals.	(18)
Lower cash receipts under the new Mount Keith 132kV expansion finance lease receivable as compared to the Southern Cross Energy finance lease receivable.	(34)
Lower cash contributions to equity accounted investments.	8
Other[1]	16
Cash flow used in investing activities for the year ended Dec. 31, 2024	**(520)**

(1) Mainly comprised of the lease incentive received, offset by lower rea ized gains on financial instruments, increase in the restricted cash balance and other investing items.

Cash used in investing activities for the year ended Dec. 31, 2023, increased compared with the same period in 2022, primarily due to the following:

	Year ended Dec. 31
Cash flow used in investing activities for the year ended Dec. 31, 2022	(741)
Lower additions to PP&E due to 2022 additions mainly for the construction of the White Rock wind projects, Garden Plain wind facility, the Horizon Hill wind project and the Northern Goldfields solar facilities. In 2023, most of these facilities achieved commercial operation.	43
Lower intangible assets due to lower additions of intangibles under development.	18
Lower proceeds on sale of PP&E due to closing the sale of two hydro facilities and equipment related to Sundance Unit 5 and other equipment in 2022.	(37)
Unfavourable change in non-cash investing working capital balances due to lower capital accruals.	(28)
Other[1]	(69)
Cash flow used in investing activities for the year ended Dec. 31, 2023	**(814)**

(1) Mainly comprised of higher spending on project development costs, higher contributions to investments, lower insurance proceeds and lower settlements in 2023.

Cash Flow Used in Financing Activities

Cash used in financing activities for the year ended Dec. 31, 2024, decreased compared with the same period in 2023, primarily due to the following:

	Year ended Dec. 31
Cash flow used in financing activities for the year ended Dec. 31, 2023	(1,432)
Acquisition of TransAlta Renewables in 2023.	811
Increase in borrowings under credit facilities during 2024.	189
Lower distributions paid to non-controlling interests.	183
Higher repurchases of common shares under the NCIB.	(56)
Lower repayments of long-term debt in 2024 compared to prior year.	33
No long-term debt issued in 2024.	(39)
Lower realized losses on financial instruments.	34
Other	(14)
Cash flow used in financing activities for the year ended Dec. 31, 2024	**(291)**

Cash used in financing activities for the year ended Dec. 31, 2023, increased compared with the same period in 2022, primarily due to the following:

	Year ended Dec. 31
Cash flow from financing activities for the year ended Dec. 31, 2022	45
Lower repayment of long-term debt due to the repayment of US$400 million senior notes in 2022.	457
Higher share capital issuance due to cash used and shares issued to acquire TransAlta Renewables.	(811)
Lower net increase in borrowings under credit facilities.	(495)
Lower issuance of long-term debt due to the Company issuing US$400 million senior notes in 2022.	(493)
Lower realized gains on financial instruments due to recognizing a gain on the repayment of US$400 million senior notes in 2022.	(72)
Higher distributions paid to non-controlling interests.	(36)
Higher repurchases of common shares under the NCIB.	(35)
Other	8
Cash flow used in financing activities for the year ended Dec. 31, 2023	**(1,432)**

Other Consolidated Analysis

Unconsolidated Structured Entities or Arrangements

Disclosure is required of all unconsolidated structured entities or arrangements such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources. We currently have no such unconsolidated structured entities or arrangements.

Related-Party Transactions

In the normal course of operations, we enter into transactions on market terms with related parties, including consolidated and equity accounted entities, which have been measured at exchange value and are recognized in the consolidated financial statements, including, but not limited to asset management fees, power purchase and derivative contracts. Refer to Note 36, Related-Party Transactions in the consolidated financial statements for further details.

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, pension plan obligations, construction projects and purchase obligations. At Dec. 31, 2024, we provided letters of credit totalling $865 million (2023 – $782 million) and cash collateral of $124 million (2023 – $145 million).

These letters of credit and cash collateral secure certain amounts included on our Consolidated Statements of Financial Position under risk management liabilities, defined benefit obligations and other long-term liabilities and decommissioning and other provisions. The increase in the amount of letters of credit issued during 2024 relates to higher physical and financial derivative transactions in a net liability position and additions of new letters of credit issued from the acquisition of Heartland.

Commitments

Contractual commitments are as follows:

	2025	2026	2027	2028	2029	2030 and thereafter	Total
Natural gas and transportation contracts[1]	75	68	65	66	64	425	763
Transmission[1]	23	23	21	10	8	105	190
Coal supply agreements[1]	75	—	—	—	—	—	75
Long-term service agreements[1]	61	47	50	31	18	151	358
Operating leases[1,2]	4	3	3	2	2	22	36
Long-term debt[3]	566	169	331	309	824	1,493	3,692
Exchangeable securities[4]	—	—	—	—	—	750	750
Principal payments on lease liabilities	4	5	5	5	5	127	151
Interest on long-term debt and lease liabilities[1][5]	205	178	169	151	136	649	1,488
Interest on exchangeable securities[1,4]	53	53	53	52	12	—	223
Growth[1]	46	3	—	—	—	—	49
Total	**1,112**	**549**	**697**	**626**	**1,069**	**3,722**	**7,775**

(1) Not recognized as a financial liability on the Conso idated Statements of Financial Position and excludes the impact of interest rate hedges.

(2) Includes leases that have not been recognized as a lease liability and leases that have not yet commenced.

(3) Excludes impact of hedge accounting and derivatives.

(4) The exchangeable debentures are due May 1, 2039 and the exchangeable preferred shares are perpetual. However, a cash payment could occur after Dec. 31, 2028, at the Company's option, if the exchangeable securities are not exchanged by Brookfield Renewable Partners or its affi iates (collectively Brookfield). At Brookfield's option, the exchangeable securities are currently exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets.

(5) Interest on long-term debt is based on debt currently in place with no assumption as to refinancing on maturity.

Contingencies

TransAlta is occasionally named as a party in various claims and legal and regulatory proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Company's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Company responds as required.

The Company conducts internal reviews of its offers and offer behaviour in both the energy and ancillary services markets in Alberta on an ongoing basis and will self-report suspected contraventions or respond to inquiries from regulatory agencies as required. There currently is no certainty that any particular matter will be resolved in the Company's favour or that such matters may not have a material adverse effect on TransAlta.

Brazeau Facility — Well Licence Applications to Consider Hydraulic Fracturing Activities

The Alberta Energy Regulator (AER) issued a subsurface order on May 27, 2019, which does not permit any hydraulic fracturing within three kilometres of the Brazeau facility, but permits hydraulic fracturing in all formations (except the Duvernay) within three to five kilometres of the Brazeau facility. Subsequently, two oil and gas operators submitted applications to the AER for 10 well licences (which include hydraulic fracturing activities) within three to five kilometres of the Brazeau facility.

The Company's position, based on independent expert analysis commissioned by the Government of Alberta, is that hydraulic fracturing activities within five kilometres of the Brazeau facility pose an unacceptable risk and that the applications should be denied. The regulatory hearing to consider these applications - Proceeding 379 - has been adjourned to November 2025.

Brazeau Facility - Claim Against the Government of Alberta

On Sept. 9, 2022, the Company filed a Statement of Claim against the Government of Alberta in the Alberta Court of King's Bench seeking a declaration that: (a) granting mineral leases within five kilometres of the Brazeau facility is a breach of a 1960 agreement between the Company and the Alberta Government; and (b) the Government of Alberta is required to indemnify the Company for any costs or damages that result from the risks of hydraulic fracturing near the Brazeau facility. On Sept. 29, 2022, the Government of Alberta filed its Statement of Defence, which asserts, among other things, that the Company: (a) is trying to usurp the jurisdiction of the AER; and (b) is out of time under the *Limitations Act* (Alberta). The trial is scheduled to be heard in September or October 2025 in the event the parties are unable to resolve the dispute prior to such date.

Garden Plain

Garden Plain I LP, a wholly-owned subsidiary of the Company, retained a third-party contractor to construct the Garden Plain wind project near Hanna, Alberta. The contractor experienced scheduling delays, challenges with construction and significant cost overruns, resulting in overdue deadlines, and has asserted a claim for $53 million in damages. The Company disputes this claim in its entirety and asserts a counterclaim. The parties have initiated the dispute resolution procedure with an arbitration hearing scheduled for three weeks starting April 14, 2025.

Sundance A Decommissioning

TransAlta filed an application with the Alberta Utilities Commission seeking payment from the Balancing Pool for TransAlta's decommissioning costs for Sundance A, including its proportionate share of the Highvale mine. The application was heard by Alberta Utilities Commission in the first quarter of 2024. A decision was rendered on Dec. 9, 2024, which directed the Balancing Pool to pay TransAlta $9 million, being the shortfall of decommissioning costs of Sundance A from previously collected amounts under the Power Purchase Arrangement Regulation.

Brazeau — Spinning Reserve Self-Report

On Nov. 30, 2022, TransAlta self-reported to the Market Surveillance Administrator (MSA) a potential violation of the Independent System Operator rules relating to offers of active spinning reserves at Brazeau when it was not properly configured to do so between Aug. 13, 2021, and Nov. 1, 2022. In 2022 a provision of $20 million was initially recognized in revenue reflecting a potential disgorgement of revenue and $2 million for potential penalties and fines. On Nov. 29, 2024, the MSA issued penalties to TransAlta for this self-report and TransAlta made a payment of $33 million in January 2025.

Financial Instruments

Financial instruments are used for proprietary trading purposes and to manage our exposure to interest rates, commodity prices and currency fluctuations, as well as other market risks. We may currently use physical and financial swaps, forward sale and purchase contracts, futures contracts, foreign exchange contracts, interest rate swaps and options to achieve our risk management objectives. Some of our physical commodity contracts have been entered into and are held for the purposes of meeting our expected purchase, sale or usage requirements and, as such, are not considered financial instruments, and are not recognized as a financial asset or financial liability. Other physical commodity contracts that are not held for normal purchase or sale requirements, and derivative financial instruments are recognized on the Consolidated Statements of Financial Position and are accounted for using the fair value method of accounting. The initial recognition of fair value and subsequent changes in fair value can affect reported earnings in the period when the change occurs if hedge accounting is not elected. Otherwise, changes in fair value will generally not affect earnings until the financial instrument is settled.

Some of our financial instruments and physical commodity contracts qualify for, and are recorded under, hedge accounting rules. The accounting for those contracts, for which we have elected to apply hedge accounting, depends on the type of hedge. Our financial instruments are mainly used for cash flow hedges or non-hedges. These categories and their associated accounting treatments are explained in further detail below.

For all types of hedges, we test for effectiveness at the end of each reporting period to determine if the instruments are performing as intended and hedge accounting can still be applied. The financial instruments we enter into are designed to ensure that future cash inflows and outflows are predictable. In a hedging relationship, the effective portion of the change in the fair value of the hedging derivative does not impact net earnings (loss), while any ineffective portion is recognized in net earnings (loss).

We have certain contracts in our portfolio that, at their inception, do not qualify for, or we have chosen not to elect to apply, hedge accounting. For these contracts, we recognize in net earnings (loss) mark-to-market gains and losses resulting from changes in forward prices compared to the price at which these contracts were transacted. These changes in price alter the timing of earnings recognition, but do not necessarily determine the final settlement amount received. The fair value of future contracts will continue to fluctuate as market prices change. The fair value of derivatives that are not traded on an active exchange, or extend beyond the time period for which exchange-based quotes are available, are determined using valuation techniques or models.

Cash Flow Hedges

Cash flow hedges are categorized as project, foreign exchange, interest rate or commodity hedges and are used to offset foreign exchange, interest rate and commodity price exposures resulting from market fluctuations.

Foreign currency forward contracts and cross-currency swaps may be used to hedge foreign exchange exposures resulting from anticipated contracts and firm commitments denominated in foreign currencies, primarily related to capital expenditures and currency exposures related to U.S. dollar denominated debt.

Physical and financial swaps, forward sale and purchase contracts, futures contracts and options may be used primarily to offset the variability in future cash flows caused by fluctuations in electricity and natural gas prices. Interest rate swaps may be used to convert the fixed interest cash flows related to interest expense on debt to floating rates and vice versa.

In a cash flow hedge, changes in the fair value of the hedging instrument (a forward contract or financial swap, for example) are recognized in risk management assets or liabilities and the related gains or losses are recognized in other comprehensive income or loss (OCI). These gains or losses are subsequently reclassified from OCI to net earnings (loss) in the same period as the hedged forecast cash flows impact net earnings (loss) and offset the losses or gains arising from the forecast transactions. For project hedges, the gains and losses reclassified from OCI are included in the carrying amount of the related PP&E.

Hedge accounting follows a principles-based approach for qualifying hedges that is aligned with an entity's approach to risk management. When we do not elect hedge accounting or when the hedge is no longer effective and does not qualify for hedge accounting, the gains or losses as a result of changes in prices, interest or exchange rates related to these financial instruments are recorded in net earnings (loss) in the period in which they arise.

Net Investment Hedges

Foreign-denominated long-term debt is used to hedge exposure to changes in the carrying values of our net investments in foreign operations that have a functional currency other than the Canadian dollar. Our net investment hedges using U.S. dollar denominated debt remain effective and in place. Gains or losses on these instruments are recognized and deferred in OCI and reclassified to net earnings on the disposal of the foreign operation. We also manage foreign exchange risk by matching foreign-denominated expenses with revenues,

such as offsetting revenues from our U.S. operations with interest payments on our U.S. dollar denominated debt.

Non-Hedges

Financial instruments not designated as hedges are used for proprietary trading and to reduce commodity price, foreign exchange and interest rate risks. Changes in the fair value of financial instruments not designated as hedges are recognized in risk management assets or liabilities and the related gains or losses are recognized in net earnings (loss) in the period in which the change occurs.

Fair Values

The majority of fair values for our foreign exchange, interest rate, commodity hedges and non-hedge derivatives are calculated using adjusted quoted prices from an active market or inputs validated by broker quotes. We may enter into commodity transactions involving non-standard features for which market-observable data is not available. These transactions are defined under IFRS as Level III instruments. Level III instruments incorporate inputs that are not observable from the market and fair value is therefore determined using valuation techniques. Fair values are validated by using reasonably possible alternative assumptions as inputs to valuation techniques and any material differences are disclosed in the notes to the consolidated financial statements.

At Dec. 31, 2024, Level III instruments had a net liabilities carrying value of $234 million (2023 – net liabilities $147 million). The Level III liabilities increased in 2024 primarily due to market price changes and the addition of contingent consideration related to the Planned Divestitures from the acquisition of Heartland, offset by contract settlements in the year. Our risk management profile and practices have not changed materially from Dec. 31, 2023.

Refer to the Material Accounting Policies and Critical Accounting Estimates section of this MD&A for further details regarding valuation techniques.

Additional IFRS Measures and Non-IFRS Measures

An additional IFRS measure is a line item, heading or subtotal that is relevant to an understanding of the consolidated financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the consolidated financial statements but is not presented elsewhere in the consolidated financial statements. We have included line items entitled gross margin and operating income (loss) in our Consolidated Statements of Earnings (Loss) for the years ended Dec. 31, 2024, 2023 and 2022. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

We use a number of financial measures to evaluate our performance and the performance of our business segments, including measures and ratios that are presented on a non-IFRS basis, as described below. Unless otherwise indicated, all amounts are in Canadian dollars and have been derived from our consolidated financial statements prepared in accordance with IFRS. We believe that these non-IFRS amounts, measures and ratios, read together with our IFRS amounts, provide readers with a better understanding of how management assesses results.

Non-IFRS amounts, measures and ratios do not have standardized meanings under IFRS. They are unlikely to be comparable to similar measures presented by other companies and should not be viewed in isolation from, as an alternative to, or more meaningful than, our IFRS results.

Non-IFRS Financial Measures

Adjusted EBITDA, FFO, FCF, Adjusted gross margin, total consolidated net debt and adjusted net debt are non-IFRS measures that are presented in this MD&A. This section provides additional information in respect of such non-IFRS measures, including a reconciliation of such non-IFRS measures to the most comparable IFRS measure.

Adjusted EBITDA

Each business segment assumes responsibility for its operating results measured by adjusted EBITDA. Adjusted EBITDA is an important metric for management that represents our core operational results. In the fourth quarter of 2024, our adjusted EBITDA composition was adjusted to exclude the impact of the Brazeau penalties assessed, the Sundance A decommissioning cost reimbursement, the ERP integration costs, revenues and expenses of the Planned Divestitures and Acquisition related and integration costs associated with the Heartland acquisition as these transactions are not reflective of ongoing operations or performance of our operating assets. Accordingly, the Company has applied this composition to all previously reported periods. Interest, taxes, depreciation and amortization are not included, as differences in accounting treatments may distort our core business results. In addition, certain reclassifications and adjustments are made to better assess results, excluding those items that may not be reflective of ongoing business performance. This presentation may facilitate the readers' analysis of trends. The most directly comparable IFRS measure is earnings before income taxes.

The following are descriptions of the adjustments made.

Adjustments to Revenue

- Adjusted EBITDA is adjusted to exclude the impact of unrealized mark-to-market gains or losses and unrealized foreign exchange gains or losses on commodity transactions.
- Adjustments are made for gains and losses related to closed positions effectively settled by offsetting positions with exchanges that have been recorded in the period the positions are settled.
- Certain assets that we own in Canada and in Western Australia are fully contracted and recorded as finance leases under IFRS. We believe that it is more appropriate to reflect the payments we receive under the contracts as a capacity payment in our revenues instead of as finance lease income and a decrease in finance lease receivables.
- The Brazeau penalties are issued by the Alberta Market Surveillance Administrator for self-reported contraventions pertaining to Hydro ancillary services provided during 2021 and 2022. The penalties have been excluded and does not represent ongoing performance. In 2022 a provision of $20 million was initially recognized in revenue reflecting a potential disgorgement of revenue and $2 million for potential penalties and fines. The final assessment contained no disgorgement of revenue and penalties of $33 million. This resulted in a reversal of the original disgorgement provision in revenue in the year ended Dec. 31, 2024 and recognition of the full amount of the penalties assessed in OM&A.
- Revenues from the Planned Divestitures are not included as they do not reflect ongoing business performance.

Adjustments to Fuel and Purchased Power

- On the commissioning of the South Hedland facility in July 2017, we prepaid approximately $74 million of electricity transmission and distribution costs. Interest income is recorded on the prepaid funds. We reclassify this interest income as a reduction in the transmission and distribution costs expensed each period to reflect the net cost to the business.

- Fuel and purchased power from the Planned Divestitures is not included as it does not reflect ongoing business performance.

Adjustments to OM&A

- Acquisition-related transaction and restructuring costs, mainly comprising severance, legal and consultant fees, are not included as these do not reflect ongoing business performance.
- The Brazeau penalties are issued by the Alberta Market Surveillance Administrator for self-reported contraventions pertaining to Hydro ancillary services provided during 2021 and 2022. The penalties have been excluded as it does not represent ongoing performance. The provision was initially recognized in 2022 based on an estimate and revised in 2024 based on the actual resolution of the matter.
- ERP integration costs representing planning and design of upgrades to the existing ERP system in 2024 are not included as they represent project costs that do not occur on a regular basis and therefore, do not reflect ongoing performance.

Adjustments to Net Other Operating Income

- The Sundance A decommissioning cost reimbursement in 2024 is not included as it relates to a settlement of a contingency for a facility that is no longer in operation. Refer to Note 8 from our consolidated financial statements for further details.
- Insurance recoveries related to the Kent Hills tower collapse in 2023 and 2022 are not included as these relate to investing activities and are not reflective of ongoing business performance.
- An onerous contract provision for future royalty payments recognized with the shutdown of the Highvale mine is excluded in 2022 as these are not part of operating income.
- Contract termination penalties in 2022 as a result of the Company's Clean Energy Transition plan are not included.

Adjustments to Earnings (Loss) in Addition to Interest, Taxes, Depreciation and Amortization

- Asset impairment charges and reversals are not included as these are accounting adjustments that impact depreciation and amortization and do not reflect ongoing business performance.
- Any gains or losses on asset sales or foreign exchange gains or losses are not included as these are not part of operating income.

Adjustments for Equity-Accounted Investments

- During the fourth quarter of 2020, we acquired a 49 per cent interest in the Skookumchuck wind facility, which is treated as an equity investment under IFRS and our proportionate share of the net earnings is reflected as equity income on the statement of earnings under IFRS. As this investment is part of our regular power-generating operations, we have included our proportionate share of the adjusted EBITDA of the Skookumchuck wind facility in our total adjusted EBITDA. In addition, in the Wind and Solar adjusted results, we have included our proportionate share of revenues and expenses to reflect the full operational results of this investment. We have not included EMG International, LLC's adjusted EBITDA in our total adjusted EBITDA as it does not represent our regular power-generating operations.

Average Annual EBITDA

Average annual EBITDA is a forward-looking non-IFRS financial measure that is used to show the average annual EBITDA that the project is expected to generate.

Funds From Operations (FFO)

FFO is an important metric as it provides a proxy for cash generated from operating activities before changes in working capital and provides the ability to evaluate cash flow trends in comparison with results from prior periods. FFO is a non-IFRS measure. For a description of the adjustments made to Cash Flow from Operations (the most directly comparable IFRS measure) to calculate FFO, see the tables on pages M70 and M74.

Adjustments to Cash Flow from Operations

- FFO related to the Skookumchuck wind facility, which is treated as an equity-accounted investment under IFRS and equity income, net of distributions from joint ventures, is included in cash flow from operations under IFRS. As this investment is part of our regular power-generating operations, we have included our proportionate share of FFO.
- Payments received on finance lease receivables are reclassified to reflect cash from operations.
- We adjust for items within the Energy Transition segment that may not be reflective of ongoing operations including certain costs related to decisions made to accelerate our transition off-coal in Alberta and our planned transition off-coal for Centralia. These are included in the "Clean energy transition provisions and adjustments" in the reconciliation.
- Sundance A decommissioning cost reimbursement in 2024 is not included as it relates to a settlement of a contingency for a facility that is no longer in operation.
- Cash received/paid on closed positions are reflected in the period that the position is settled.
- We adjust for costs associated with acquisition-related transactions or restructuring and that are not reflective of ongoing operations.
- Other adjustments include payments/receipts for production tax credits, which are reductions to tax equity

debt and include distributions from equity-accounted joint ventures.

Free Cash Flow (FCF)

FCF is an important metric as it represents the amount of cash that is available to invest in growth initiatives, make scheduled principal repayments on debt, repay maturing debt, pay common share dividends or repurchase common shares. Changes in working capital are excluded so FFO and FCF are not distorted by changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and timing of receipts and payments. FCF is a non-IFRS measure. For a description of the adjustments made to Cash Flow from Operations (the most directly comparable IFRS measure) to calculate FCF, see the tables on pages M70 and M74.

Adjusted Gross Margin

Adjusted gross margin is calculated as adjusted revenues less adjusted fuel and purchased power and carbon compliance costs, where adjustments to revenue or fuel and purchased power were applied as stated above. The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment. The most directly comparable measure is gross margin in the consolidated statement of earnings.

Non-IFRS Ratios

FFO per share, FCF per share and adjusted net debt to adjusted EBITDA are non-IFRS ratios that are presented in the MD&A. Refer to the Reconciliation of Cash Flow from Operations to FFO and FCF and Key Non-IFRS Financial Ratios sections of this MD&A for additional information.

FFO per Share and FCF per Share

FFO per share and FCF per share are calculated using the weighted average number of common shares outstanding during the period. FFO per share and FCF per share are non-IFRS ratios.

Supplementary Financial Measures

Sustaining capital expenditures and growth and development expenditures are supplementary financial measures used to present our spend related to facilitate safe and reliable operation of our existing facilities and the construction of projects, respectively. Refer to the Capital Expenditures section of this MD&A for additional information.

The Alberta electricity portfolio metrics disclosed are supplementary financial measures used to present the gross margin by segment for the Alberta market. Refer to the Alberta Portfolio section of this MD&A for additional information.

Full-Year Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segment

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings before income taxes for the year ended Dec. 31, 2024:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	409	357	1,350	616	168	(34)	2,866	(21)	—	2,845
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	1	84	(60)	(36)	14	—	3	—	(3)	—
Realized gain (loss) on closed exchange positions	—	—	7	2	(15)	—	(6)	—	6	—
Decrease in finance lease receivable	—	2	19	—	—	—	21	—	(21)	—
Finance lease income	—	6	8	—	—	—	14	—	(14)	—
Revenues from Planned Divestitures	—	—	(1)	—	—	—	(1)	—	1	—
Brazeau penalties	(20)	—	—	—	—	—	(20)	—	20	—
Unrealized foreign exchange loss on commodity	—	—	(2)	—	—	—	(2)	—	2	—
Adjusted revenues	390	449	1,321	582	167	(34)	2,875	(21)	(9)	2,845
Fuel and purchased power	16	30	475	418	—	—	939	—	—	939
Reclassifications and adjustments:										
Fuel and purchased power related to Planned Divestitures	—	—	(1)	—	—	—	(1)	—	1	—
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted fuel and purchased power	16	30	470	418	—	—	934	—	5	939
Carbon comp iance	—	—	145	1	—	(34)	112	—	—	112
Gross margin	374	419	706	163	167	—	1,829	(21)	(14)	1,794
OM&A	86	97	198	69	36	173	659	(4)	—	655
Reclassifications and adjustments:										
Brazeau penalties	(31)	—	—	—	—	—	(31)	—	31	—
ERP integration costs	—	—	—	—	—	(14)	(14)	—	14	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(24)	(24)		24	—
Adjusted OM&A	55	97	198	69	36	135	590	(4)	69	655
Taxes, other than income taxes	3	16	13	3	—	1	36	—	—	36
Net other operating income	—	(10)	(40)	(9)	—	—	(59)	—	—	(59)
Reclassifications and adjustments:										
Sundance A decommissioning cost reimbursement	—	—	—	9	—	—	9	—	(9)	—
Adjusted net other operating income	—	(10)	(40)	—	—	—	(50)	—	(9)	(59)
Adjusted EBITDA[2]	316	316	535	91	131	(136)	1,253			
Equity income										5
Finance lease income										14
Depreciation and amortization										(531)
Asset impairment charges										(46)
Interest income										30
Interest expense										(324)
Foreign exchange gain										5
Gain on sale of assets and other										4
Earnings before income taxes										319

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings before income taxes for the year ended Dec. 31, 2023:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	533	357	1,514	751	220	1	3,376	(21)	—	3,355
Reclassifications and adjustments:										
Unrealized mark-to-market loss	(4)	16	(67)	(5)	23	—	(37)	—	37	—
Realized gain (loss) on closed exchange positions	—	—	10	—	(91)	—	(81)	—	81	—
Decrease in finance lease receivable	—	—	55	—	—	—	55	—	(55)	—
Finance lease income	—	—	12	—	—	—	12	—	(12)	—
Unrealized foreign exchange gain on commodity	—	—	1	—	—	—	1	—	(1)	—
Adjusted revenues	529	373	1,525	746	152	1	3,326	(21)	50	3,355
Fuel and purchased power	19	30	453	557	—	1	1,060	—	—	1,060
Reclassifications and adjustments:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted fuel and purchased power	19	30	449	557	—	1	1,056	—	4	1,060
Carbon compliance	—	—	112	—	—	—	112	—	—	112
Gross margin	510	343	964	189	152	—	2,158	(21)	46	2,183
OM&A	48	80	192	64	43	115	542	(3)	—	539
Taxes, other than income taxes	3	12	11	3	—	1	30	(1)	—	29
Net other operating income	—	(7)	(40)	—	—	—	(47)		—	(47)
Reclassifications and adjustments:										
Insurance recovery	—	1	—	—	—	—	1	—	(1)	—
Adjusted net other operating income	—	(6)	(40)	—	—	—	(46)	—	(1)	(47)
Adjusted EBITDA[2]	459	257	801	122	109	(116)	1,632			
Equity income										4
Finance lease income										12
Depreciation and amortization										(621)
Asset impairment reversals										48
Interest income										59
Interest expense										(281)
Foreign exchange gain										(7)
Gain on sale of assets and other										4
Earnings before income taxes										880

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings before income taxes for the year ended Dec. 31, 2022:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	606	303	1,209	714	160	(2)	2,990	(14)		2,976
Reclassifications and adjustments:										
Unrea ized mark-to-market (gain) loss	1	104	251	10	12	—	378	—	(378)	—
Realized gain (loss) on closed exchange positions	—	—	(4)	—	47	—	43	—	(43)	—
Decrease in finance lease receivable	—	—	46	—	—	—	46	—	(46)	—
Finance lease income	—	—	19	—	—	—	19	—	(19)	—
Brazeau penalties	20	—	—	—	—	—	20	—	(20)	—
Unrea ized foreign exchange gain on commodity	—	—	—	—	(1)	—	(1)	—	1	—
Adjusted revenues	627	407	1,521	724	218	(2)	3,495	(14)	(505)	2,976
Fuel and purchased power	22	31	641	566	—	3	1,263	—	—	1,263
Reclassifications and adjustments:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted fuel and purchased power	22	31	637	566	—	3	1,259	—	4	1,263
Carbon comp iance	—	1	83	(1)	—	(5)	78	—	—	78
Gross margin	605	375	801	159	218	—	2,158	(14)	(509)	1,635
OM&A	55	68	195	69	35	101	523	(2)	—	521
Reclassifications and adjustments:										
Brazeau penalties	(2)	—	—	—	—	—	(2)	—	2	—
Adjusted OM&A	53	68	195	69	35	101	521	(2)	2	521
Taxes, other than income taxes	3	12	15	4	—	1	35	(2)	—	33
Net other operating income	—	(23)	(38)	—	—	—	(61)	3	—	(58)
Reclassifications and adjustments:										
Royalty onerous contract and contract termination penalties	—	7	—	—	—	—	7	—	(7)	—
Adjusted net other operating income	—	(16)	(38)	—	—	—	(54)	3	(7)	(58)
Adjusted EBITDA[2][3]	549	311	629	86	183	(102)	1,656			
Equity income										9
Finance lease income										19
Depreciation and amortization										(599)
Asset impairment charges										(9)
Interest income										24
Interest expense										(286)
Foreign exchange gain										4
Gain on sale of assets and other										52
Earnings before income taxes										353

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(3) During 2024 our adjusted EBITDA composition was amended to exclude the impact of Brazeau penalties and related provisions. Therefore, the Company has applied this composition to all previously reported periods. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Full-Year Reconciliation of Cash Flow from Operations to FFO and FCF

The table below reconciles our cash flow from operating activities to our FFO and FCF:

	2024	2023	2022
Cash flow from operating activities[1]	**796**	1,464	877
Change in non-cash operating working capital balances	**(38)**	(124)	316
Cash flow from operations before changes in working capital	**758**	1,340	1,193
Adjustments			
Share of adjusted FFO from joint venture[1]	**8**	8	8
Decrease in finance lease receivable	**21**	55	46
Clean energy transition provisions and adjustments[2]	**—**	11	42
Sundance A decommissioning cost reimbursement	**(9)**	—	—
Realized gain (loss) on closed exchanged positions	**(6)**	(81)	37
Acquisition-related transaction and restructuring costs	**19**	—	—
Other[3]	**19**	18	20
FFO[4]	**810**	1,351	1,346
Deduct:			
Sustaining capital[1]	**(142)**	(174)	(142)
Productivity capital	**(1)**	(3)	(4)
Dividends paid on preferred shares	**(52)**	(51)	(43)
Distributions paid to subsidiaries' non-controlling interests	**(40)**	(223)	(187)
Principal payments on lease liabilities	**(6)**	(10)	(9)
FCF[4]	**569**	890	961
Weighted average number of common shares outstanding in the period	**302**	276	271
FFO per share[4]	**2.68**	4.89	4.97
FCF per share[4]	**1.88**	3.22	3.55

(1) Includes our share of amounts for the Skookumchuck wind facility, an equity-accounted joint venture.

(2) 2023 includes amounts related to onerous contracts recognized in 2021 and a voluntary contribution to the U.S. Defined Benefit Pension Plan for the Centralia thermal facility. During 2022, to support the employees affected by the closure of the Highvale mine and our transition off coal to cleaner sources, the Company made a voluntary special contribution of $35 million to the Highvale mine pension plan. 2022 also includes amounts related to onerous contracts recognized in 2021.

(3) Other consists of production tax credits, which is a reduction to tax equity debt, less distributions from an equity-accounted joint venture.

(4) These items are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The table below provides a reconciliation of our adjusted EBITDA to our FFO and FCF:

Year ended Dec. 31	2024	2023	2022[5]
Adjusted EBITDA[1][4]	**1,253**	1,632	1,656
Provisions	**10**	(1)	25
Net interest expense[2]	**(231)**	(164)	(200)
Current income tax expense	**(143)**	(50)	(65)
Realized foreign exchange loss	**(27)**	(4)	—
Decommissioning and restoration costs settled	**(41)**	(37)	(35)
Other non-cash items	**(11)**	(25)	(35)
FFO[3][4]	**810**	1,351	1,346
Deduct:			
Sustaining capital[4]	**(142)**	(174)	(142)
Productivity capital	**(1)**	(3)	(4)
Dividends paid on preferred shares	**(52)**	(51)	(43)
Distributions paid to subsidiaries' non-controlling interests	**(40)**	(223)	(187)
Principal payments on lease liabilities	**(6)**	(10)	(9)
FCF[3][4]	**569**	890	961

(1) Adjusted EBITDA is defined in the Additional IFRS Measures and Non-IFRS Measures section of this MD&A and reconciled to earnings (loss) before income taxes above.

(2) Net interest expense includes interest expense less interest income and excludes non-cash items ike financing amortization and accretion.

(3) These items are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. FFO and FCF are defined in the Additional IFRS Measures and Non-IFRS Measures section of this MD&A and reconciled to cash flow from operating activities above.

(4) Includes our share of amounts for the Skookumchuck wind faci ity, an equity-accounted joint venture.

(5) During 2024 our adjusted EBITDA composition was amended to exclude the impact of Brazeau penalties and related provisions. Therefore, the Company has applied this composition to all previously reported periods. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Fourth Quarter Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segment

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings before income taxes for the three months ended Dec. 31, 2024:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	93	104	319	155	14	—	685	(7)	—	678
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	4	23	26	(8)	19	—	64	—	(64)	—
Realized gains (losses) on closed exchange positions	—	—	(1)	2	1	—	2	—	(2)	—
Decrease in finance lease receivable	—	1	5	—	—	—	6	—	(6)	—
Finance lease income	—	2	3	—	—	—	5	—	(5)	—
Revenues from Planned Divestitures	—	—	(1)	—	—	—	(1)	—	1	—
Brazeau penalties	(20)	—	—	—	—	—	(20)	—	20	—
Unrealized foreign exchange gain on commodity	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted revenues	77	130	350	149	34	—	740	(7)	(55)	678
Fuel and purchased power	3	8	136	102	—	—	249	—	—	249
Reclassifications and adjustments:										
Fuel and purchased power related to Planned Divestitures	—	—	(1)	—	—	—	(1)	—	1	—
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	3	8	134	102	—	—	247	—	2	249
Carbon comp iance	—	—	39	—	—	—	39	—	—	39
Gross margin	74	122	177	47	34	—	454	(7)	(57)	390
OM&A	47	27	67	19	7	68	235	(1)	—	234
Reclassifications and adjustments:										
Brazeau penalties	(31)	—	—	—	—	—	(31)	—	31	—
ERP integration costs	—	—	—	—	—	(14)	(14)	—	14	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(16)	(16)	—	16	—
Adjusted OM&A	16	27	67	19	7	38	174	(1)	61	234
Taxes, other than income taxes	1	3	4	—	—	—	8	1	—	9
Net other operating income	—	(3)	(10)	(9)	—	—	(22)	—	—	(22)
Reclassifications and adjustments:										
Sundance A decommissioning cost reimbursement	—	—	—	9	—	—	9	—	(9)	—
Adjusted net other operating income	—	(3)	(10)	—	—	—	(13)	—	(9)	(22)
Adjusted EBITDA[2]	57	95	116	28	27	(38)	285			
Equity income										2
Finance lease income										5
Depreciation and amortization										(143)
Asset impairment charges										(20)
Interest income										11
Interest expense										(92)
Foreign exchange gain										17
Loss before income taxes										(51)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The following table reflects adjusted EBITDA by segment and provides reconciliation to loss before income taxes for the three months ended Dec. 31, 2023:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	77	94	246	175	39	—	631	(7)	—	624
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(2)	20	53	7	(19)	—	59	—	(59)	—
Realized gain on closed exchange positions	—	—	23	—	4	—	27	—	(27)	—
Decrease in finance lease receivable	—	—	15	—	—	—	15	—	(15)	—
Finance lease income	—	—	2	—	—	—	2	—	(2)	—
Unrealized foreign exchange gain on commodity	—	—	1	—	—	—	1	—	(1)	—
Adjusted revenues	75	114	340	182	24	—	735	(7)	(104)	624
Fuel and purchased power	5	8	127	138	—	—	278	—	—	278
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	5	8	126	138	—	—	277	—	1	278
Carbon comp iance	—	—	27	—	—	—	27	—	—	27
Gross margin	70	106	187	44	24	—	431	(7)	(105)	319
OM&A	13	25	56	18	10	29	151	(1)	—	150
Taxes, other than income taxes	1	1	—	—	—	1	3	—	—	3
Net other operating income	—	(3)	(10)	—	—	—	(13)	—	—	(13)
Reclassifications and adjustments:										
Insurance recovery	—	1	—	—	—	—	1	—	(1)	—
Adjusted net other operating income	—	(2)	(10)	—	—	—	(12)	—	(1)	(13)
Adjusted EBITDA[2]	56	82	141	26	14	(30)	289			
Equity income										3
Finance lease income										2
Depreciation and amortization										(132)
Asset impairment charges										(26)
Interest income										12
Interest expense										(66)
Foreign exchange loss										(7)
Loss before income taxes										(35)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Fourth Quarter Reconciliation of Cash Flow from Operations to FFO and FCF

The table below reconciles our cash flow from operating activities to our FFO and FCF:

Three months ended Dec. 31	2024	2023
Cash flow from operating activities[1]	**215**	310
Change in non-cash operating working capital balances	**(97)**	(135)
Cash flow from operations before changes in working capital	**118**	175
Adjustments		
Share of adjusted FFO from joint venture[1]	**4**	3
Decrease in finance lease receivable	**6**	15
Clean energy transition provisions and adjustments[2]	**—**	4
Sundance A decommissioning cost reimbursement	**(9)**	—
Realized gain on closed exchanged positions	**2**	27
Acquisition-related transaction and restructuring costs	**11**	—
Other[3]	**5**	5
FFO[3]	**137**	229
Deduct:		
Sustaining capital[1]	**(67)**	(74)
Productivity capital	**(1)**	(1)
Dividends paid on preferred shares	**(13)**	(12)
Distributions paid to subsidiaries' non-controlling interests	**(6)**	(19)
Principal payments on lease liabilities	**(3)**	(2)
Other	**1**	—
FCF[4]	**48**	121
Weighted average number of common shares outstanding in the period	**298**	308
FFO per share[4]	**0.46**	0.74
FCF per share[4]	**0.16**	0.39

(1) Includes our share of amounts for Skookumchuck, an equity-accounted joint venture. The amount for the fourth quarter of 2023 was adjusted to conform to current period presentation.

(2) Includes amounts related to onerous contracts recognized in 2021 and a voluntary contribution to the U.S. Defined Benefit Pension Plan for the Centralia thermal faci ity.

(3) Other consists of production tax credits, which is a reduction to tax equity debt, less distributions from the equity-accounted joint venture.

(4) These items are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The table below provides a reconciliation of our adjusted EBITDA to our FFO and FCF for the three months ended Dec 31. 2024 and 2023:

Three months ended Dec. 31	2024	2023
Adjusted EBITDA[1][4]	**285**	289
Provisions	**2**	(1)
Net interest expense[2]	**(64)**	(41)
Current income tax (expense) recovery	**(20)**	5
Realized foreign exchange loss (gain)	**(20)**	9
Decommissioning and restoration costs settled	**(12)**	(15)
Other non-cash items	**(34)**	(17)
FFO[3][4]	**137**	229
Deduct:		
Sustaining capital[4]	**(67)**	(74)
Productivity capital	**(1)**	(1)
Dividends paid on preferred shares	**(13)**	(12)
Distributions paid to subsidiaries' non-controlling interests	**(6)**	(19)
Principal payments on lease liabilities	**(3)**	(2)
Other	**1**	—
FCF[3][4]	**48**	121

(1) Adjusted EBITDA is defined in the Additional IFRS Measures and Non-IFRS Measures section of this MD&A and reconciled to earnings (loss) before income taxes above.

(2) Net interest expense includes interest expense less interest income and excludes non-cash items ike financing amortization and accretion.

(3) These items are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. FFO and FCF are defined in the Additional IFRS Measures and Non-IFRS Measures section of this MD&A and reconciled to cash flow from operating activities above.

(4) Includes our share of amounts for the Skookumchuck wind faci ity, an equity-accounted joint venture.

Key Non-IFRS Financial Ratios

The methodologies and ratios used by rating agencies to assess our credit rating are not publicly disclosed. We have developed our own definitions of ratios and targets to help evaluate the strength of our financial position.

These metrics and ratios are not defined and have no standardized meaning under IFRS and may not be comparable to those used by other entities or by rating agencies.

Adjusted Net Debt to Adjusted EBITDA

Year ended Dec. 31	2024	2023	2022
Credit facilities, long-term debt and lease liabilities[1]	**3,808**	3,466	3,653
Exchangeable debentures	**350**	344	339
Less: Cash and cash equivalents[2]	**(336)**	(345)	(1,118)
Add: 50 per cent of issued preferred shares and exchangeable preferred shares[3]	**671**	671	671
Other[4]	**(24)**	(12)	(20)
Adjusted net debt[5]	**4,469**	4,124	3,525
Adjusted EBITDA[6][7]	**1,253**	1,632	1,656
Adjusted net debt to adjusted EBITDA (times)	**3.6**	2.5	2.1

(1) Consists of current and non-current portions of long-term debt, which includes lease iabi ities and tax equity financing.

(2) Cash and cash equivalents, net of bank overdraft.

(3) Exchangeable preferred shares are considered equity with dividend payments for credit-rating purposes. For accounting purposes, they are accounted for as debt with interest expense in the consolidated financial statements. For purposes of this ratio, we consider 50 per cent of issued preferred shares, including these, as debt.

(4) Includes principal portion of TransAlta OCP restricted cash ($17 million for 2024, 2023 and 2022) and fair value of hedging instruments on debt (included in risk management assets and/or iabi ities on the Conso idated Statements of Financial Position).

(5) The tax equity financing for the Skookumchuck wind faci ity, an equity-accounted joint venture, is not represented in this amount. Adjusted net debt is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Presenting this item from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(6) Last 12 months.

(7) During 2024 our adjusted EBITDA composition was amended to exclude the impact of Brazeau penalties and related provisions. Therefore, the Company has applied this composition to all previously reported periods. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The Company's capital is managed using a net debt position. We use the adjusted net debt to adjusted EBITDA ratio as a measurement of financial leverage and to assess our ability to service debt. Our target for adjusted net debt to adjusted EBITDA is 3.0 to 4.0 times. Our adjusted net debt to adjusted EBITDA ratio for Dec. 31, 2024 was higher compared to Dec. 31, 2023, due to higher adjusted net debt resulting from the assumption of Heartland debt, lower cash balances due to cash paid to acquire Heartland on Dec. 4, 2024 and lower adjusted EBITDA in 2024 compared to 2023.

2025 Outlook

For 2025, the Company expects adjusted EBITDA to be in the range of $1.15 to $1.25 billion and FCF to be in the range of $450 to $550 million which is based on the following:

- Higher contribution from the wind and solar portfolio due to a full-year impact of new asset additions of the White Rock and Horizon Hill wind facilities;
- Contribution from assets acquired with Heartland;
- Lower contributions from the legacy merchant hydro, wind and gas assets in Alberta which are expected to step down due to lower expected average power prices in Alberta given baseload gas and renewables supply additions in late 2024 and 2025;
- Lower current income tax expense in 2025 compared to 2024 actual; and
- Increased net interest expense in 2025 as a result of the Heartland acquisition and lower interest income earned on lower cash deposits and lower capitalized interest on growth projects.

The following table outlines our expectations on key financial targets and related assumptions for 2025 and should be read in conjunction with the narrative discussion that follows and the Governance and Risk Management section of this MD&A:

Measure	2025 Target	2024 Target	2024 Actual
Adjusted EBITDA[(1)]	$1,150 to $1,250 million	$1,150 to $1,300 million	$1,253 million
FCF[(1)(2)]	$450 to $550 million	$450 to $600 million	$569 million
FCF per share	$1.51 to $1.85	$1.47 to $1.96	$1.88
Dividend per share	$0.26 annualized	$0.24 annualized	$0.24 annualized

(1) These items are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Reconci iation of Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. See also the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The Company's outlook for 2025 may be impacted by a number of factors as detailed further below.

Range of key 2025 power and gas price assumptions

Market	2025 Assumptions	2024 Assumptions	2024 Actual
Alberta spot ($/MWh)	$40 to $60	$75 to $95	$63
Mid-Columbia spot (US$/MWh)	US$50 to US$70	US$85 to US$95	US$76
AECO gas price ($/GJ)	$1.60 to $2.10	$2.50 to $3.00	$1.29

Alberta spot price sensitivity: a +/- $1 per MWh change in spot price is expected to have a +/-$3 million impact on adjusted EBITDA for 2025.

Other assumptions relevant to the 2025 outlook

Measure	2025 Expectations	2024 Expectations	2024 Actual
Energy Marketing gross margin	$110 to $130 million	$110 to $130 million	$167 million
Sustaining capital	$145 to $165 million	$130 to $150 million	$142 million
Current income tax expense	$95 to $130 million	$95 to $130 million	$143 million
Net interest expense	$255 to $275 million	$240 to $260 million	$231 million

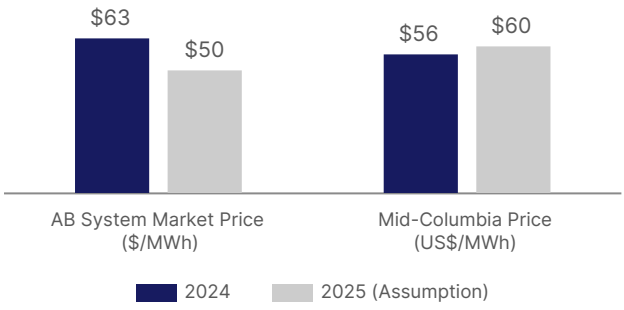
Alberta Hedging

Range of hedging assumptions	Q1 2025	Q2 2025	Q3 2025	Q4 2025	2026
Hedged production (GWh)	2,117	1,758	1,942	1,845	4,713
Hedge price ($/MWh)	$72	$70	$70	$70	$75
Hedged gas volumes (GJ)	14 million	6 million	6 million	6 million	18 million
Hedge gas prices ($/GJ)	$2.98	$3.63	$3.77	$3.65	$3.67

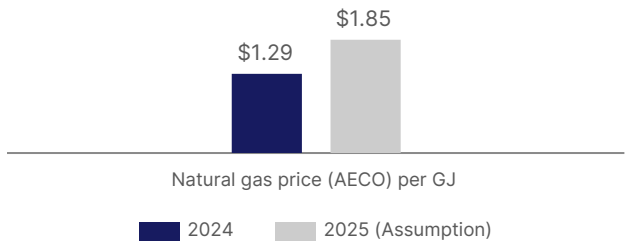
Market Pricing

The following graphs include 2025 pricing based on a range of assumptions and are subject to change:

Annual Average Spot Electricity Prices



Annual Average Gas (AECO) Prices



For 2025, spot electricity prices in Alberta are expected to be lower compared to 2024, driven by normalized weather expectations and the addition of new natural gas and cogeneration, and wind and solar supply. Spot electricity prices in the Pacific Northwest are expected to be comparable in 2025, but will depend on natural gas prices and the actual hydrology for the region during the year.

AECO natural gas prices are expected to be higher than in 2024.

The objective of our portfolio management strategy in Alberta is to balance opportunity and risk and to deliver optimization strategies that contribute to our total investment, which includes a return on invested capital. We can be more or less hedged in a given period, and we expect to realize our annual targets through a combination of forward hedging and selling generation into the spot market. The assets within the Alberta electricity portfolio are managed as a portfolio to maximize the overall value of generation and capacity from our hydro, wind, energy storage and thermal facilities. Hedging is a key component of cash flow certainty and the hedges are primarily tied to our portfolio of gas facilities and also allocated to our portfolio of hydro facilities rather than a single facility.

Sustaining Capital Expenditures

Our estimate for total sustaining capital is as follows:

	Spent in 2024	Expected spend in 2025
Total sustaining capital	$142 million	$145 to $165 million

The Company expects sustaining capital to be in the range of $145 to $165 million. The midpoint for the range represents an 11 per cent increase from the midpoint of the 2024 expected sustaining capital range of $130 to $150 million, and a nine per cent increase from 2024 sustaining capital spend. This is driven by increased Hydro dam safety spending and the additional capital requirements to support Heartland gas facilities, offset by lower sustaining capital expenditures for planned major maintenance related to our other gas facilities and lower sustaining capital from our Energy Transition segment as 2025 is our Centralia plant's final year of coal-fired generation.

Liquidity and Capital Resources

We maintain adequate available liquidity under our committed credit facilities. As at Dec. 31, 2024, we had access to $1.6 billion in liquidity, including $336 million in cash, which exceeds the funds required for committed growth, sustaining capital and productivity projects.

Material Accounting Policies and Critical Accounting Estimates

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as accounting rules and guidance have changed. Accounting rules generally do not involve a selection among alternatives, but involve the implementation and interpretation of existing rules and the use of judgment relative to the circumstances existing in the business. Every effort is made to comply with all applicable rules on or before the effective date and we believe the proper implementation and consistent application of accounting rules is critical.

However, not all situations are specifically addressed in the accounting literature. In these cases, our best judgment is used to adopt a policy for accounting for these situations. We draw analogies to similar situations and the accounting guidelines governing them, consider foreign accounting standards and consult with our independent auditors about the appropriate interpretation and application of these policies. Each of the critical accounting policies involves complex situations and a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our consolidated financial statements.

Our material accounting policies are described in Note 2 of the consolidated financial statements. Each policy involves a number of estimates and assumptions to be made about matters that are uncertain at the time the estimate is made. Different estimates, with respect to key variables used for the calculations, or changes to estimates, could potentially have a material impact on our financial position or results of operations.

We have discussed the development and selection of these critical accounting estimates with the Audit, Finance and Risk Committee (AFRC) of the Board of Directors and our independent auditors. The AFRC has reviewed and approved our disclosure relating to critical accounting estimates in this MD&A. These critical accounting estimates are described as follows:

Tariff

On Feb. 1, 2025, the President of the United States issued three executive orders directing the United States to impose new tariffs on imports originating from Canada, Mexico and China. These orders call for additional 25 per cent duty on imports into the United States of Canadian-origin and Mexican-origin products and 10 per cent duty on Chinese-origin products, except for Canadian energy resources that are subject to an additional 10 per cent duty. On Feb. 3, 2025, a 30-day pause on potential tariffs was implemented. The actual tariffs and their impacts to the Company remain uncertain. The Company is assessing the direct and indirect impacts to its business of such tariffs, retaliatory tariffs or other trade protectionist measures implemented as this situation develops.

Revenue Recognition

Revenue from Contracts with Customers

Identification of Performance Obligations

Where contracts contain multiple promises for goods or services, management exercises judgment in determining whether goods or services constitute distinct goods or services or a series of distinct goods or services that are substantially the same and that have the same pattern of transfer to the customer. The determination of a performance obligation affects whether the transaction price is recognized at a point in time or over time. Management considers both the mechanics of the contract and the economic and operating environment of the

contract in determining whether the goods or services in a contract are distinct.

Transaction Price

In determining the transaction price and estimates of variable consideration, management considers the past history of customer usage and capacity requirements when estimating the goods and services to be provided to the customer. The Company also considers the historical production levels and operating conditions for its variable generating assets.

Allocation of Transaction Price to Performance Obligations

When multiple performance obligations are present in a contract, transaction price is allocated to each performance obligation in an amount that depicts the consideration the Company expects to be entitled to in exchange for transferring the good or service.

The Company's contracts generally outline a specific amount to be invoiced to a customer associated with each performance obligation in the contract. Where contracts do not specify amounts for individual performance obligations, the Company estimates the amount of the transaction price to allocate to individual performance obligations based on their standalone selling price, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

Satisfaction of Performance Obligations

The satisfaction of performance obligations requires management to use judgment as to when control of the underlying good or service transfers to the customer. Determining when a performance obligation is satisfied affects the timing of revenue recognition. Management considers both customer acceptance of the good or service and the impact of laws and regulations such as certification requirements in determining when this transfer occurs. Management also applies judgment to determine whether the invoice practical expedient permits recognition of revenue at the invoiced amount if that invoiced amount corresponds directly with the entity's performance to date.

Revenue from Other Sources

Revenue from Derivatives

Commodity risk management activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, futures contracts and options that are used to earn revenues and to gain market information. These derivatives are accounted for using fair value accounting. The determination of the fair value of commodity risk management contracts and derivative instruments is complex and relies on judgments concerning future prices, volatility and liquidity, among other factors. Some of our derivatives are not traded on an active exchange or extend beyond the time period for which exchange-based quotes are available, requiring us to use internal valuation techniques or other models such as numerical derivative valuation or scenario analysis.

Merchant Revenue

Revenues from non-contracted capacity (i.e., merchant) are composed of energy payments, at market price, for each MWh produced and are recognized upon delivery.

Financial Instruments

The fair value of a financial instrument is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by reference to prices for instruments in active markets to which we have access. In the absence of an active market, we determine fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, we look primarily to external readily observable market inputs. However, if not available, we use inputs that are not based on observable market data.

Level Determinations and Classifications

The Level I, II and III classifications in the fair value hierarchy are utilized by the Company. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value. Refer to Note 14(I) and (II) from our consolidated financial statements for further details on the inputs used for each level.

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques for contracts included in the Level III fair value measurements at Dec. 31, 2024, is an estimated total upside of $200 million (2023 – $194 million) and total downside of $146 million (2023 – $116 million) impact to the carrying value of the financial instruments. Fair values are stressed for unobservable inputs, which can include variable volumes, unobservable prices and wind discounts, among other inputs. The variable volumes are stressed up and down based on historically available production data. Prices are stressed for longer-term deals where there are no liquid market quotes using various internal and external forecasting sources to establish a high and a low price range. Wind discounts represent price to volume relationships and are stressed specific to each location.

In addition to the Level III fair value measurements discussed above, the Brookfield Investment Agreement allows Brookfield the option to exchange all of the outstanding exchangeable securities into an equity ownership interest of up to a maximum of 49 per cent in an entity formed to hold TransAlta's Alberta Hydro Assets

after Dec. 31, 2024. The fair value of the option to exchange is considered a Level III fair value measurement, with an estimated downside of $30 million (2023 – $25 million) potential impact to the carrying value of nil as at Dec. 31, 2024 (2023 – nil). The sensitivity analysis has been prepared using the Company's assessment that a change in the implied discount rate of the future cash flow of one per cent is a reasonably possible change.

Valuation of PP&E and Associated Contracts

At the end of each reporting period, we assess whether there is any indication that PP&E and finite life intangible assets are impaired or whether a previously recognized impairment may no longer exist or may have decreased.

Our operations, the market and business environment are routinely monitored and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the asset or cash-generating unit (CGU) to which the asset belongs. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose. The recoverable amount is the higher of an asset's fair value less costs of disposal or its value in use. Fair value is the price that would be received to sell an asset in an orderly transaction between market participants at the measurement date. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if none is available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset. In estimating either fair value less costs of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, capital expenditures, retirement costs and other related cash inflows and outflows over the life of the facilities, which can range from 30 to 49 years. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the facility operates, anticipated production levels, planned and unplanned outages, changes to regulations and transmission capacity or constraints for the remaining life of the facilities.

Discount rates are determined by employing a weighted average cost of capital methodology that is based on capital structure, cost of equity and cost of debt assumptions based on comparable companies with similar risk characteristics and market data as the asset, CGU or group of CGUs subject to the test. These estimates and assumptions are susceptible to change from period to period and actual results can and often do differ from the estimates and can have either a positive or negative impact on the estimate of the impairment charge and may be material.

The impairment outcome can also be impacted by the determination of CGUs or groups of CGUs for asset and goodwill impairment testing. The allocation of goodwill is reassessed upon changes in the composition of segments, CGUs or groups of CGUs. In respect of determining CGUs, significant judgment is required to determine what constitutes independent cash flows between power facilities that are connected to the same system. We evaluate the market design, transmission constraints and the contractual profile of each facility, as well as our commodity price risk management plans and practices, in order to inform this determination. With regard to the allocation or reallocation of goodwill, significant judgment is required to evaluate synergies and their impacts. Minimum thresholds also exist with respect to segmentation and internal monitoring activities.

We evaluate synergies with regard to opportunities from combined talent and technology, functional organization and future growth potential and we consider our own performance measurement processes in making this determination. No changes arose in our CGUs in 2024.

PP&E impairment charges can be reversed in future periods if circumstances improve. No assurances can be given if any reversal will occur or the amount or timing of any such reversal.

Asset Impairments

During 2024, the Company recorded asset impairment charges of $24 million related to retired assets due to changes in discount rates and cash flow revisions. Refer to Note 24 and 7 in our consolidated financial statements for further details.

Valuation of Goodwill

We evaluate goodwill for impairment at least annually, or more frequently if indicators of impairment exist. If the carrying amount of a CGU or group of CGUs, including goodwill, exceeds the unit's fair value, the excess represents a goodwill impairment loss.

For the purposes of the 2024 goodwill impairment review, the Company determined the recoverable amounts of the Wind and Solar segment by calculating the fair value less costs of disposal using discounted cash flow projections. In 2024, the Company relied on the recoverable amounts determined in 2023 for the Hydro and Energy Marketing segments in performing the 2024 goodwill impairment review. The recoverable amounts are based on the

Company's long-range forecasts for the periods extending to the last planned asset retirement in 2072. The resulting fair value measurement is categorized within Level III of the fair value hierarchy. We have determined there were no goodwill impairments for 2024, 2023 and 2022.

Determining the fair value of the CGUs or group of CGUs is susceptible to changes from period to period as management is required to make assumptions about future cash flows, including estimates of contracted and future market prices based on expected market supply and demand in the region in which the facility operates, anticipated production levels, planned and unplanned outages, changes to regulations and transmission capacity or constraints for the remaining life of the facilities.

The significant assumptions impacting the determination of fair value for the Wind and Solar segment, with a high degree of subjectivity, are the following:

• Forecasts of sales prices for each facility are determined by taking into consideration contract prices for facilities subject to long- or short-term contracts, forward price curves for merchant plants and regional supply-demand balances. Where forward price curves are not available for the duration of the facility's useful life, prices are determined by extrapolation techniques using historical industry and company-specific data. Merchant electricity prices used in Wind and Solar models ranged between $40 to $225 per MWh during the forecast period (2023 – $35 to $238 per MWh).

• Discount rates used ranged from 6.4 to 7.3 per cent (2023 – 6.4 to 7.5 per cent).

• The White Rock and Horizon Hill wind facilities are subject to location specific price basis, sourced from third party analysis. This analysis is based on models of the transmission system, including assumptions around potential system upgrades as well as forecasted generation and load in the area.

Project Development Costs

Project development costs include external, direct and incremental costs that are necessary for completing an acquisition or construction project. The appropriateness of capitalization of these costs is evaluated each reporting period and amounts capitalized for projects no longer probable of occurring are charged to net earnings (loss). At the end of each reporting period, we assess whether there is any indication that capitalized project development costs are impaired by evaluating the effect of any significant adverse events on projects, including the evaluation of whether the criteria for capitalization continues to be appropriate. During 2024, the Company recognized impairment of project development costs related to projects that are no longer proceeding. Refer to note 7 of our consolidated financial statements.

Useful Life of PP&E

Each significant component of an item of PP&E is depreciated over its estimated useful life. A component is a tangible asset that can be separately identified as an asset and is expected to provide a benefit of greater than one year. Estimated useful lives are determined based on current facts and past experience and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, the potential for technological obsolescence and regulations. The useful lives of PP&E and depreciation rates used are reviewed at least annually to ensure they continue to be appropriate.

Change in Estimate — Useful Lives

During 2024 and 2023, the Company adjusted the useful lives of certain assets in the Gas segment to reflect changes to the future operating expectations of the assets. This resulted in a decrease of $112 million (2023 - $92 million) in depreciation expense that was recognized in the Consolidated Statement of Earnings in 2024 and 2023, respectively.

Leases

In determining whether the Company's contracts contain, or are, leases, management must use judgment to assess whether the contract provides the customer with the right to substantially all of the economic benefits from the use of the asset during the lease term and whether the customer obtains the right to direct the use of the asset during the lease term. For those agreements considered to contain, or be, leases, further judgment is required to determine the lease term by assessing whether termination or extension options are reasonably certain to be exercised. Judgment is also applied in identifying in-substance fixed payments (included) and variable payments that are based on usage or performance factors (excluded) and in identifying lease and non-lease components (services that the supplier performs) of contracts and in allocating contract payments to lease and non-lease components.

For leases where the Company is a lessor, judgment is required to determine if substantially all of the significant risks and rewards of ownership are transferred to the customer or remains with the Company, to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant and impact how we classify amounts related to the arrangement as either PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position and therefore the amount of certain items of revenue and expense are dependent upon such classifications.

Income Taxes

Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which we operate. The process also involves making an estimate of taxes currently payable and income taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. An assessment must also be made to determine the likelihood that our future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. The reduction of the deferred income tax asset can be reversed if the estimated future taxable income improves. No assurances can be given if any reversal will occur or the amount or timing of any such reversal. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations and legislation to ensure that deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than our estimates could materially impact the amount recognized for deferred income tax assets and liabilities. Our tax filings are subject to audit by taxation authorities. The outcome of some audits may change our tax liability, although we believe that we have adequately provided for income taxes in accordance with IFRS based on all information currently available. The outcome of pending audits is not known nor is the potential impact on the consolidated financial statements determinable.

Employee Future Benefits

We provide selected pension and other post-employment benefits to employees, such as health and dental benefits. The cost of providing these benefits depends on many factors, including actual plan experience and estimates and assumptions about future experience.

The liabilities for pension, other post-employment benefits and associated pension costs included in annual compensation expenses are impacted by employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans and earnings on plan assets.

Changes to the provisions of the plans may also affect current and future pension costs. Pension costs may also be significantly impacted by changes in key actuarial assumptions, including, for example, the discount rates used in determining the defined benefit obligation and the net interest cost on the net defined benefit liability. The discount rate used to estimate our obligation reflects high-quality corporate fixed income securities currently available and expected to be available during the period to maturity of the pension benefits.

Defined Benefit Obligation

The liability for pension and post-employment benefits and associated costs included in compensation expenses are impacted by estimates related to changes in key actuarial assumptions, including discount rates. The defined benefit obligation has decreased by $9 million to $146 million as at Dec. 31, 2024, from $155 million as at Dec. 31, 2023. A one per cent increase in discount rates would have a $34 million impact on the defined benefit obligation.

Decommissioning and Restoration Provisions

We recognize decommissioning and restoration provisions for generating facilities and mine sites in the period in which they are incurred if there is a legal or constructive obligation to remove the facilities and restore the site. The amount recognized as a provision is the best estimate of the expenditures required to settle the provision. Expected values are probability weighted to deal with the risks and uncertainties inherent in the timing and amount of settlement of many decommissioning and restoration provisions. Expected values are discounted at the current market-based risk-free interest rate adjusted to reflect the market's evaluation of our credit standing.

The Company recognizes provisions for decommissioning obligations. Initial decommissioning provisions and subsequent changes thereto, are determined using the Company's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement.

On Dec. 4, 2024 as part of the Heartland acquisition, the Company recognized decommissioning and restoration provision of $101 million.

During 2024, the decommissioning and restoration provision increased by $21 million due to revisions in estimated cash flows and timing of cash flows for certain Gas and Hydro assets. The timing of cash flows was adjusted to optimize and maximize efficiencies by staging required reclamation work. Operating assets included in PP&E increased by $14 million and $7 million was recognized as an impairment charge in net earnings related to retired assets.

During 2024, revisions in discount rates increased the decommissioning and restoration provision by $35 million due to a decrease in discount rates. On average, discount rates decreased compared to 2023, with rates ranging from 5.3 to 8.4 per cent as at Dec. 31, 2024. This has resulted in a corresponding increase in PP&E of $18 million on operating assets and the recognition of a $17 million impairment charge in net earnings related to retired assets.

Other Provisions

Where necessary, we recognize provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation and force majeure claims. These provisions and subsequent changes thereto are determined using our best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized. As part of the acquisition of Heartland, the Company recognized an onerous contract provision of $47 million related to certain natural gas transportation contracts assumed. Payments required under the contracts continue through the first quarter of 2031.

Classification of Joint Arrangements

Upon entering into a joint arrangement, the Company must classify it as either a joint operation or joint venture and the classification affects the accounting for the joint arrangement. In making this classification, the Company exercises judgment in evaluating the terms and conditions of the arrangement to determine whether the parties have rights to the assets and obligations or rights to the net assets. Factors such as the legal structure, contractual arrangements and other facts and circumstances, such as where the purpose of the arrangement is primarily for the provision of the output to the parties and when the parties are substantially the only source of cash flows for the arrangement, must be evaluated to understand the rights of the parties to the arrangement.

Significant Influence

Upon entering into an investment, the Company must classify it as either an investment as an associate or an investment under IFRS 9. In making this classification, the Company exercises judgment in evaluating whether the Company has significant influence over the investee. Significant influence is the power to participate in the financial and operating policy decisions of the investee, but is not control or joint control over those policies. If the Company holds 20 per cent or more of the voting rights in the investee, it is presumed that the entity has significant influence, unless it can be clearly demonstrated that this is not the case. Other factors such as representation on the board of directors, participation in policy-making processes, material transactions between the Company and investee, interchange of managerial personnel or providing essential technical information are considered when assessing if the Company has significant influence over an investee.

Accounting Changes

Current Accounting Changes

Amendments to IAS 1 — Non-current Liabilities with Covenants and Classification of Liabilities as Current or Non-current

In October 2022, the IASB issued Non-current Liabilities with Covenants, which amends IAS 1 Presentation of Financial Statements, to clarify how conditions with which an entity must comply within 12 months after the reporting period affect the classification of a liability. In January 2020, the IASB issued Classification of Liabilities as Current or Non-current, which amends IAS 1 Presentation of Financial Statements regarding the classification of liabilities as current or non-current, clarifying that contractual rights and conditions existing at the end of the reporting period are relevant in determining whether the Company has a right to defer settlement of a liability by at least 12 months.

Additionally, the IASB clarified that the classification of a liability is unaffected by the likelihood that an entity will exercise its deferral right. The amendments are applied retrospectively, effective for annual periods beginning on or after Jan. 1, 2024, and were adopted by the Company on that date.

The Company has an Investment Agreement whereby Brookfield Renewable Partners or its affiliates (collectively, Brookfield) invested $750 million in TransAlta through the purchase of exchangeable securities (Exchangeable Securities), which are exchangeable into an equity ownership interest in TransAlta's Alberta hydro assets in the future. On Jan. 1, 2024, the Company reclassified the Exchangeable Securities from non-current liabilities to current liabilities as the conversion option can be exercised at any time after Dec. 31, 2024, although there is no obligation to deliver cash equivalent resources and the holder cannot call for repayment. This accounting is consistent with the amendment.

Future Accounting Changes

Amendments to IFRS 9 and IFRS 7 — Nature-Dependent Electricity Contracts

On Dec. 18, 2024, the IASB issued amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosure to improve reporting of the financial effects of nature-dependent electricity (e.g., wind and solar) contracts, which are often structured as power purchase agreements. Under these contracts, the amount of electricity generated can vary based on uncontrollable factors such as weather conditions. The amendments clarify the application of own-use requirements, permit hedge accounting if these contracts are used as hedging instruments and add new disclosure requirements about the effect of these contracts on a company's financial performance and cash flows. The amendments are effective for annual reporting periods beginning on or after Jan. 1, 2026. The Company is currently evaluating the impacts to the financial statements.

Amendments to IFRS 7 and IFRS 9 — Classification and Measurement of Financial Instruments

On May 29, 2024, the IASB issued Amendments to the Classification and Measurement of Financial Instruments effective Jan. 1, 2026 impacting IFRS 7 and 9. The IASB amended the requirements related to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets, including those with ESG-linked features. The Company is currently evaluating the impacts to the financial statements.

IFRS 18 — Presentation and Disclosure in Financial Statements

On April 9, 2024, the IASB issued a new standard, IFRS 18 *Presentation and Disclosure in Financial Statements*, which introduced new requirements for improved comparability in the statement of profit or loss, enhanced transparency of management-defined performance measures and more useful grouping of information in the financial statements. The standard is effective for annual reporting periods beginning on or after Jan. 1, 2027. The Company is currently evaluating the impacts to the financial statements.

Sustainability

Sustainability, or environmental, social and governance (ESG) management and performance, is a core value at TransAlta. Sustainability is integrated into our governance, decision-making, risk management and day-to-day business processes. Our focus on continuous improvement on material sustainability factors seeks to mitigate ESG-related risks and provides long-term value creation to our stakeholders. TransAlta's sustainability pillars support our corporate strategy and weave through our business. Our sustainability pillars were refreshed in 2024 and include:

- **Reliable and Responsible Electricity Production**
- **Safe, Healthy, Diverse and Engaged Workplace**
- **Positive Indigenous, Stakeholder, Customer and Employee Relationships**
- **Environmental Stewardship**
- **Technology and Innovation**

Reporting on Our Material Sustainability Factors

TransAlta has been reporting on sustainability since 1994. The Company's sustainability reporting is integrated within this MD&A to provide information on how sustainability factors affect our business and is guided by leading sustainability reporting frameworks. We partially adopt guidance from the Canadian Sustainability Standards Board, International Sustainability Standards Board, International Financial Reporting Standards (IFRS) Foundation, Integrated Reporting Framework, Global Reporting Initiative (GRI) and the Sustainability Accounting Standards Board (SASB) requirements for electric utilities and power generators. We continue to monitor the development of sustainability- and climate-related disclosure requirements in the jurisdictions in which we operate to assess our future reporting obligations.

Since 2007, TransAlta's material sustainability data to be disclosed has received limited assurance from independent third-party providers. Climate-related information to be disclosed is partially informed by the IFRS S2 Climate-related Disclosures Standard and the recommendations of the Task Force on Climate-related Financial Disclosures (TCFD).

In 2024, we reviewed and updated our management response to our 2021 climate-related scenario analysis. We also reviewed and updated our Climate Transition Plan and climate-related financial metrics. GHG emissions data for scopes 1, 2 and 3 follow the accounting and reporting standards of the GHG Protocol. For further information on climate change management and the findings of our scenario analysis, refer to the Transitioning Our Energy Mix section of this MD&A.

Disclosure of our most relevant sustainability factors in 2024 remained unchanged from 2022 and is guided by our most recent materiality assessment. In 2022, we refreshed our materiality assessment by evaluating key sector-specific research, supported by internal and external engagement on key sustainability factors. Our Enterprise Risk Management (ERM) program is designed to help the Company focus its efforts on key enterprise risks, within the planning horizon that could significantly impact the success of our strategy, including our sustainability objectives.

Key topics identified within SASB, TCFD, IFRS and the Taskforce on Nature-related Financial Disclosures (TNFD) were reviewed to inform the identification of our material sustainability factors. We also considered sustainability factors from the electricity sector through Electricity Canada's 2021 Sustainable Electricity Report and conducted a peer review of material sustainability factors. This work, validated by our executive team, resulted in the identification of 21 material sustainability factors, which are presented in the Sustainability Governance section of this MD&A.

For further guidance on our risk factors, refer to the Governance and Risk Management section of this MD&A.

Our 2024 Sustainability Performance

Performance against our 2024 sustainability targets is outlined below and excludes the acquisition of Heartland Generation on Dec. 4, 2024 (refer to the Significant and Subsequent Events section of this MD&A). Target year means by Dec. 31 of that year. For more information on all our sustainability performance indicators, refer to the Sustainability Performance Indicators section of this report.

ESG Alignment: Environmental

Sustainability goal	Sustainability target	Results	Comments
Reduce GHG emissions	By 2026, achieve a 75 per cent reduction of scope 1 and 2 GHG emissions from 2015 base year[1]	*On track*	Since 2015, we have reduced scope 1 and 2 GHG emissions by 22.7 MT CO_2e or 70 per cent.
	By 2045, achieve net-zero for 100 per cent of TransAlta's scope 1 and 2 GHG emissions[2]	*On track*	
	By 2024, verify and disclose 80 per cent of TransAlta's scope 3 emissions	*Achieved*	We received limited assurance on 93 per cent of TransAlta's scope 3 emissions in 2024.
Reduce air emissions	By 2026, achieve a 95 per cent reduction of SO_2 emissions and an 80 per cent reduction of NO_x emissions below 2005 levels	*Achieved in 2022*	We achieved this target in 2022 through the reduction of our SO_2 emissions by 98 per cent and NO_x emissions by 83 per cent from 2005 levels. In 2024, we retained the achievement of this target.
Reclaim land utilized for mining	By 2040, complete full reclamation of our Centralia coal mine in Washington State	*On track*	Reclamation work at Centralia is underway and 44 per cent of the coal mine land has been reclaimed.
	By 2046, complete full reclamation of our Highvale coal mine in Alberta	*On track*	Our Highvale coal mine in Alberta closed in 2021. Reclamation work is underway and 22 per cent of the coal mine land has been reclaimed.
Responsible water management	By 2026, reduce fleet-wide water consumption (withdrawals minus discharge) by 20 million m^3 or 40 per cent over a 2015 baseline	*Achieved in 2022*	We achieved this target in 2022 through the reduction of our fleet-wide water consumption by approximately 20 million m^3 or 43 per cent from 2015 levels. In 2024, we retained the achievement of this target.
Protecting nature and biodiversity	By 2024, assess and disclose nature-related risks and opportunities including TransAlta's dependencies and impacts on ecosystems, land, water and air	*Achieved*	Assessment of nature-related risks and opportunities was completed in 2024.
	Achieve zero biodiversity-related incidents[3]	*Achieved*	We recorded zero (0) biodiversity-related incidents.

(1) Gross GHG emissions reduction target, which does not include uti ization of internally generated and externally purchased emission credits. TransAlta does not plan to use carbon credits to achieve its 2026 GHG emissions reduction target.

(2) Target covers 100 per cent of TransAlta's operating assets. The Company may choose to neutra ize residual emissions from gas-fired generation through fuel switching, new technologies or nature-based solutions to achieve its 2045 net-zero target. For further information, refer to the Climate Transition Plan in the Transitioning Our Energy Mix section of this MD&A.

(3) Biodiversity-related incidents are significant environmental incidents that affect habitats and species included on the Red List of the International Union for Conservation of Nature and are classified as near-threatened, vulnerable, endangered and critically endangered.

ESG Alignment: Social

Sustainability goal	Sustainability target	Results	Comments
Reduce safety incidents	Achieve a Total Recordable Injury Frequency (TRIF) rate below 0.32 with a goal of 0.00	*Not Achieved*	We recorded a TRIF rate of 0.56 compared to 0.30 in 2023. We recorded zero serious injuries in 2024. The identification and control of high-energy hazards is foundational to our strong performance on serious injury prevention.
Integrate sustainability into supply chain	By 2024, 80 per cent of our spend will be with suppliers that have a sustainability policy or commitment	*Not Achieved*	On average, 79 per cent of our spend in 2022, 2023 and 2024 was with suppliers that have a sustainability policy or commitment.
Support prosperous Indigenous communities	Support equal access to all levels of education for youth and Indigenous peoples through financial support and employment opportunities	*On track*	Support represented a total value of $320,000, or 11 per cent of TransAlta's total community investment.
	Provide Indigenous cultural awareness training during the onboarding of all new TransAlta employees[1]	*Achieved*	We provided Indigenous awareness training to 100 per cent of employees in Canada, the U.S. and Western Australia onboarded in 2024.

ESG Alignment: Governance

Sustainability goal	Sustainability target	Results	Comments
Strengthen gender equality	Achieve 50 per cent female representation on the Board by 2030	*On track*	As at Dec. 31, 2024, women represented 38 per cent of our Board composition, compared to 46 per cent in 2023.[2]
	Achieve at least 40 per cent female employment among all employees of the Company by 2030	*On track*	As at Dec. 31, 2024, women represented 28 per cent of all employees, an increase over 2023 levels (27 per cent).
	Maintain equal pay for women in equivalent roles as men	*Achieved*	We achieved a 99 per cent female/male pay equity ratio. We strive to maintain this ratio within a deviation of plus or minus three per cent.
Demonstrate leadership on ESG reporting within financial disclosures	Maintain our position as a leader on integrated ESG disclosure through increased annual alignment with leading sustainability disclosure frameworks	*On track*	In 2024, TransAlta received an award for best ESG reporting (mid-cap) by the IR Magazine Canada. We also received the Sustainability, ESG and Purpose Award from the Governance Professionals of Canada. This award underscores our commitment to embedding sustainability into our governance, strategy and risk management practices.[3]

(1) TransAlta employees have 60 days to complete onboarding training; hence, this target refers to employees onboarded from Jan. 1 to Oct. 31, 2024.

(2) Board composition includes all independent directors, and our President and CEO who is not independent. In 2024, we achieved 50 per cent female representation on the Board, excluding the two nominees from Brookfield.

(3) A description of the specific set of criteria and/or methodology used by the IR Magazine Canada can be found at https://events.irmagazine.com/canadaawards. The Governance Professionals of Canada 2024 Report of the Judges can be found at https://www.f ipsnack.com/gpcanada/2024-gpc-eg-awards-judges-report/full-view.html.

ESG Alignment: Environmental and Social

Sustainability goal	Sustainability target	Results	Comments
Coal transition	No further coal generation by the end of 2025 with 100 per cent of our owned net generation capacity to be from renewables and gas	*On track*	We retired 670 MW of coal-fired generation at Centralia on Dec. 31, 2020. In 2021, we retired or converted all coal plants in Canada and closed the Highvale coal mine, thus ceasing all coal generation in Canada. We plan to cease coal-fired generation at our Centralia plant by Dec. 31, 2025.
Clean energy solutions for customers	Develop new renewable projects that support customer sustainability goals to achieve both long-term power price affordability and carbon reductions	*On track*	Since 2021, we have added over 800 MW of new capacity through renewable projects such as Windrise (206 MW), Garden Plain (130 MW), Northern Goldfields Solar (48 MW), White Rock (302 MW) and Horizon Hill (202 MW). As a result, our U.S. renewables fleet represents over 1 GW.

2025+ Sustainability Targets

Our 2025 and longer-term sustainability targets support the performance of our business. Goals and targets are established to manage current and emerging material sustainability factors in support of the United Nations Sustainable Development Goals (UN SDGs) and the Future-Fit Business Benchmark, which defines sustainable goals for businesses.

In 2024, TransAlta updated four sustainability targets in the areas of air emissions, water resources, safety and Indigenous relations, while setting a new climate-related target to achieve a 30 per cent reduction of our scope 1 and 2 GHG emissions intensity by 2030 from a 2023 base year.

We have maintained our climate-related targets to achieve net-zero of scope 1 and 2 GHG emissions by 2045 and to reduce 75 per cent of our scope 1 and 2 GHG emissions by 2026 from a 2015 base year. This target covers 100 per cent of TransAlta's operating assets and is estimated to align with the electricity sector decarbonization pathway to limit global warming to 1.5°C, as one of the Paris Agreement goals.

Targets are outlined below. Target year means by Dec. 31 of that year.

ESG Alignment: Environmental

Sustainability goal	Sustainability target	Alignment with UN SDG Target or Future-Fit Business Benchmark
Reduce GHG emissions	By 2026, achieve a 75 per cent reduction of scope 1 and 2 GHG emissions from 2015 base year[1]	UN SDG Target 13.2: "Integrate climate change measures into national policies, strategies and planning"
	By 2030, achieve a 30 per cent reduction of scope 1 and 2 GHG emissions intensity from 2023 base year	
	By 2045, achieve net-zero for scope 1 and 2 GHG emissions[2]	
Reduce air emissions	By 2030, achieve a 90 per cent reduction of SO_2 emissions intensity from 2023 base year	UN SDG Target 9.4: "By 2030, upgrade infrastructure and retrofit industries to make them sustainable, with increased resource-use efficiency and greater adoption of clean and environmentally sound technologies and industrial processes"
Reclaim land utilized for mining	By 2040, complete full reclamation of our Centralia coal mine in Washington State	Future-Fit Business Benchmark: "Positive Pursuits 13: Ecosystems are restored"
	By 2046, complete full reclamation of our Highvale coal mine in Alberta	Future-Fit Business Benchmark: "Positive Pursuits 13: Ecosystems are restored"
Manage water resources	By 2030, maintain water consumption intensity at 2023 levels	UN SDG Target 6.4: "By 2030, substantially increase water-use efficiency across all sectors and ensure sustainable withdrawals and supply of freshwater to address water scarcity and substantially reduce the number of people suffering from water scarcity"
Protect nature and biodiversity	Achieve zero biodiversity-related incidents[3]	UN SDG Target 15.5: "Take urgent and significant action to reduce the degradation of natural habitats, halt the loss of biodiversity and, by 2020, protect and prevent the extinction of threatened species"
Transition away from coal	Cease coal generation by the end of 2025 with 100 per cent of our owned net generation capacity to be from renewables and gas	UN SDG Target 7.1: "By 2030, ensure universal access to affordable, reliable and modern energy services"

(1) Gross GHG emissions reduction target, which does not include uti ization of internally generated and externally purchased emission credits. TransAlta does not plan to use carbon credits to achieve its 2026 GHG emissions reduction target. The Company may choose to update this target to include the acquisition of Heartland Generation on Dec. 4, 2024, in alignment with internationally recognized methodologies such as the GHG Protocol.

(2) Target covers 100 per cent of TransAlta's operating assets. The Company may choose to neutra ize residual emissions from gas-fired generation through fuel switching, new technologies or nature-based solutions to achieve its 2045 net-zero target. For further information, refer to the Climate Transition Plan in the Transitioning Our Energy Mix section of this MD&A.

(3) Biodiversity-related incidents are significant environmental incidents that affect habitats and species included on the Red List of the International Union for Conservation of Nature and are classified as near-threatened, vulnerable, endangered and critically endangered.

ESG Alignment: Social

Sustainability goal	Sustainability target	Alignment with UN SDG Target or Future-Fit Business Benchmark
Reduce safety incidents	Achieve a Total Recordable Injury Frequency rate below 0.37 with a goal of 0.00	UN SDG Target 8.8: "Protect labour rights and promote safe and secure working environments for all workers, including migrant workers, in particular women migrants, and those in precarious employment"
Support prosperous Indigenous communities	Support access to education and wellbeing for Indigenous communities	UN SDG Target 4.5: "By 2030, eliminate gender disparities in education and ensure equal access to all levels of education and vocational training for the vulnerable, including persons with disabilities, Indigenous peoples and children in vulnerable situations"
	Provide Indigenous cultural awareness training during the onboarding of all new TransAlta employees	UN SDG Target 12.8: "By 2030, ensure that people everywhere have the relevant information and awareness for sustainable development and lifestyles in harmony with nature"

ESG Alignment: Governance

Sustainability goal	Sustainability target	Alignment with UN SDG Target or Future-Fit Business Benchmark
Strengthen gender equality	Achieve 50 per cent female representation on the Board by 2030	UN SDG Target 5.5: "Ensure women's full and effective participation and equal opportunities for leadership at all levels of decision making in political, economic and public life"
	Achieve at least 40 per cent female employment among all employees of the Company by 2030	
	Maintain equal pay for women in equivalent roles as men	

Transitioning Our Energy Mix

We recognize the impact of climate change on society and our business both today and into the future. TransAlta's renewable energy journey began 113 years ago when we built the first hydro assets in Alberta, which still operate today. In 1993, we began operating our first wind facility, which was the first commercial wind facility in Canada; in 2014, we acquired our first solar facility; and, in 2020, we constructed our first battery storage facility. Today, we operate 60 renewable power facilities across Canada, the U.S. and Western Australia.

Our reporting on climate change management has been guided by the TCFD recommendations since 2018. In 2024, we partially adopted guidance from IFRS S2, which is based on the TCFD recommendations with industry-specific climate metrics based on the SASB standards.

Strategy and Risk Management

Climate Change Strategy

As described in the following sections, our risks and opportunities assessment and scenarios analysis support the development and continuous improvement of our climate change strategy. We actively monitor and manage climate-related risks and opportunities to ensure we remain resilient across scenarios.

TransAlta remains committed to creating a path to resiliency in a decarbonizing world in support of the goals adopted under the Paris Agreement, and the goals adopted during subsequent international climate meetings. Our strategy is focused on the operation of our existing assets (wind, hydro, solar, natural gas, battery storage and coal), the phase-out of coal-fired electricity generation, the development of renewable energy and storage, and the use of natural gas generation to ensure reliability.

Our customers continue to integrate climate risk into their business decisions; therefore, we see an advantage in our renewable power business to support our customers' sustainability goals. From 2000 to 2024, we increased our nameplate renewable power capacity from approximately 900 MW to over 3,600 MW. Today, TransAlta is one of the largest producers of wind power in Canada, and the largest producer of hydro power in Alberta.

Another way we contribute to our customers' sustainability goals is through environmental attributes. The environmental attributes we generate include carbon offsets, renewable energy credits and emission offsets. Our customers use environmental attributes to lower compliance costs attributed to carbon policies or renewable portfolio standards. Environmental attributes can also help achieve voluntary corporate sustainability or carbon reduction goals.

To combat the challenges of renewable energy intermittency, we continue to invest in battery storage and evaluate the role of natural gas to provide reliability and flexibility. In 2020, we launched WindCharger, a "first-of-its-kind in Alberta" battery storage project that stores energy produced by our Summerview II wind facility and discharges electricity into the Alberta grid during system supply shortages, as well as providing critical system support services to the system operator. This project received co-funding from Emissions Reduction Alberta. Further, in 2021, we agreed to provide solar electricity supported with a battery energy storage system to BHP Nickel West through the construction of the Northern Goldfields hybrid solar project in Western Australia. The Northern Goldfields solar and battery storage facilities were commissioned in 2023. In 2022, TransAlta entered into an agreement for the expansion of the Mount Keith 132kV transmission system. The expansion was completed in February 2024.

We have also taken important steps to reduce our carbon footprint over the last several years. In 2021, we adopted a more stringent climate-related target to reduce 75 per cent of scope 1 and 2 GHG emissions by 2026 from a 2015 base year. This target covers 100 per cent of TransAlta's operating assets and is estimated to align with the electricity sector decarbonization pathway to limit global warming to 1.5°C, as one of the Paris Agreement goals. Furthermore, we adopted a long-term climate-related target to achieve net-zero for 100 per cent of TransAlta's scope 1 and 2 GHG emissions by 2045. This target aligns with the Canadian Net-Zero Emissions Accountability Act to achieve net-zero emissions by 2050.

Since 2018, we have retired 4,464 MW of coal-fired generation capacity, while converting 1,659 MW to natural gas. Comparatively, our converted natural gas units' CO_2 intensity is approximately 57 per cent less than coal-fired generation. Repurposing these facilities rather than decommissioning them reduces the cost and emissions associated with new construction, and aligns with the UN SDGs, specifically "Goal 9: Industry, Innovation and Infrastructure." Completed conversions and the closure of our Highvale coal mine also contribute to the goals of the Powering Past Coal Alliance, which TransAlta joined in 2021 at COP26. In 2025, we plan to cease coal-fired operations at our sole remaining coal unit, located in the U.S., to complete TransAlta's transition away from coal-fired electricity generation.

We engage with policymakers and stakeholders involved in the energy transition to ensure that parties understand the need to maintain reliable, sustainable and affordable energy as countries move to net-zero electricity systems. At TransAlta, we plan to continue investing in renewables and assessing the best options to deliver energy storage.

At the same time, we believe that natural gas plays an essential role in the electricity sector, providing critical reliable, dispatchable generation to support current systems demands.

Climate Transition Plan

A climate-related transition plan describes how a company aims to minimize climate-related risks and increase opportunities, in alignment with IFRS S2 and TCFD. In 2024, TransAlta updated its Climate Transition Plan, which outlines our approach to reducing operational and value chain emissions with the target to deliver net-zero operations by 2045. Our Climate Transition Plan includes sustainable finance and inclusive transition actions that reflect TransAlta's commitment to a progress toward a lower-carbon economy. For further information, refer to Sustainable Finance in the Transitioning Our Energy Mix section of this MD&A and Inclusive Transition in the Engaging with Our Stakeholders to Create Positive Relationships section of this MD&A.

Our Climate Transition Plan defines TransAlta's past, short-term (2025-2027) and medium- to long-term actions (beyond 2028). For each of these actions, we assessed our ability to control (C) intended outcomes, partner (P) with stakeholders to drive outcomes or influence (I) outcomes that will help us achieve our decarbonization targets.

The highest level of climate-change oversight, including the actions of our Climate Transition Plan, is at the Board of Directors (Board) level. For further information, refer to Oversight by the Board of Directors in the Climate Change Governance section of this MD&A. Information on executive compensation linked to climate-related targets is described in ESG-Linked Compensation in the Building a Diverse and Inclusive Workforce section of this MD&A. Metrics and targets supporting our Climate Transition Plan, including climate-related financial metrics, are described in Climate Change Metrics and Targets in the Transitioning Our Energy Mix section of this MD&A.

Climate Transition Plan

	Past actions	Short-term actions (2025-2027)	Medium to long-term actions (2028 +)
Hydro	Became the largest producer of hydro power in Alberta (C)	Evaluate and deploy investments in renewable projects, where appropriate (C)	Evaluate and deploy investments in renewable projects, where appropriate (C)
Wind and solar	From 2000 to 2024, we grew our nameplate renewables capacity by approximately 2,200 MW (C)		
Battery storage	First battery storage facility delivered in 2020 (C) In 2023, completed the construction of a 48 MW solar and battery storage system in Western Australia (C)	Evaluate and deploy battery storage, where appropriate (C)	Evaluate and deploy battery storage, where appropriate (C)
Natural gas	Converted 1,659 MW from coal to natural gas since 2018 (C) Completed our coal-to-gas conversions in Canada in 2021 (C)	Operate simple-cycle, combined-cycle and cogeneration facilities in Canada, the U.S. and Western Australia (C) Assess deployment of nature-based or engineered solutions to neutralize unabated gas-fired generation where appropriate (C) Evaluate use of renewable and low-carbon natural gas (C)	Neutralize residual GHG emissions (scopes 1 and 2) from gas-fired generation through fuel switching, new technologies or nature-based solutions (C)
Emerging abatement technologies and solutions	In 2023, started partnership to target early-stage revolutionary technologies through a US$25 million investment in a deep decarbonization fund (P) In 2023, started an electric vehicle pilot project in our hydro operations (C) In 2024, started a partnership to study the deployment of a small modular nuclear reactor at the site of an existing coal-to-gas plant in Alberta (P) In 2024, continued to support the development of low-cost, low-emissions hydrogen production through a $2 million investment in a Canadian-based venture (P)	Identify the next generation of power solutions and technologies and potential for parallel investments in new complementary sectors by the end of 2025 (P) Assess ways to support customers with broader decarbonization technologies beyond electrification (P) Identify opportunities to partner, pilot and deploy novel, net-zero generation technologies (P) Assess and deploy GHG removal technologies where appropriate (C) Evaluate the electrification of our vehicle fleet (C)	Deploy new net-zero generation technologies and solutions where appropriate (C) Choose materials, products and processes that generate fewer GHG emissions, mainly through energy savings (C) Evaluate the electrification of our vehicle fleet (C)
Energy transition (coal)	Retired 4,464 MW of coal-fired generation capacity since 2018 including ending coal generation in Canada in 2021 (C) Ceased coal mining in Canada in 2021 and in the U.S. in 2006 (C) In 2023, started partnership to repurpose landfilled fly ash to advance low-carbon concrete projects in Alberta (P)	Continue to execute reclamation work at our coal mines (C) Cease coal-fired generation by the end of 2025 (C) Contribute to a circular economy through mining waste reuse or by-product sales (C)	Complete full reclamation in Washington State by 2040 and in Alberta by 2046 (C)

Climate Transition Plan (Continued)

	Past actions	Short-term actions (2025-2027)	Medium to long-term actions (2028 +)
Supply chain	Enhanced supplier management functionality within the corporate procurement system (C) From 2022 to 2024, 79 per cent of our spend was with suppliers that had a sustainability policy or commitment (C)	Develop ESG criteria for supply chain engagement (C) Understand direct suppliers, their GHG emissions profile and targets (C) Incorporate ESG data reporting capability in corporate procurement system (C)	Engage with suppliers to explore enhancement of their GHG emissions reduction targets (I) Consider setting direction for engaging suppliers with GHG emissions reduction targets (C)
Value chain	Updated scope 3 GHG emissions reporting methodology (C) In 2024, verified and disclosed 93 per cent of our total scope 3 emissions (C)	Consider scope 3 GHG emissions targets (C) Consider verification and disclosure of remaining scope 3 GHG emissions (C)	Consider scope 3 GHG emissions targets (C)
Sustainable finance	In 2021, converted existing $1.3 billion loan into a Sustainability-Linked Loan aligned with our GHG emissions reduction and female employment targets (C) In 2021, secured $173 million green bond financing for an eligible wind project in Alberta (C) In 2022, issued US$400 million Senior Green Bonds for eligible renewable energy and energy-efficiency projects (C) Linked ESG performance to employees' and executive remuneration (C)	Continue to evaluate the use of sustainable or green financing instruments to fund renewable energy and battery storage projects (C) Link ESG performance to employees' and executive remuneration (C)	Continue to evaluate the use of sustainable or green financing instruments to grow our renewables and storage capacity (C) Link ESG performance to employees' and executive remuneration (C)
Inclusive transition	Developed a five-year Equity, Diversity and Inclusion (ED&I) strategy (C) Conducted an ED&I census to measure progress (C) Set employee engagement and ED&I targets as part of ESG-linked compensation (C) Since 2023, launched four employee resource groups (C) Since 2022, provided Indigenous cultural awareness training to all employees (C) From 2012 to 2023, invested US$55 million to support energy efficiency, economic and community development and education and retraining initiatives in Washington State (P) Since 2016, invested in the communities impacted by the phase-out of coal generation in Alberta (P)	Empower employees through culture champions to foster a culture of allyship, inclusion and belonging (C) Adapt workplaces to incorporate structural changes for inclusive work environments (C) Embed ED&I into our culture strategy and daily work activities (C) Continue to invest in the communities impacted by the phase-out of coal generation in Alberta (P) Strengthen Indigenous relations focused on community engagement and consultation, community investment and partnership opportunities (P) Promote supplier diversity in our operations (C)	Advance recruitment and retention of female employees to progress towards gender-based targets (C) Maintain succession practices to increase diverse representation at the senior management level (C) Increase female representation in Generation by encouraging women to pursue a career in electricity (C) Enhance opportunities for diverse suppliers in our procurement processes (C) Continue to enhance our Indigenous relations focused on partnership opportunities with local communities (P) Provide ongoing support to local community organizations aligned with our community investment pillars where we operate and grow (P)

Climate Change Governance

Climate-related risks and opportunities can significantly impact our business. We therefore actively manage such risks and opportunities so that we can continue to grow and achieve our goals. Climate-related issues are identified at every level of management, including the Board, executive team, business units and corporate functions.

Oversight by the Board of Directors

The highest level of climate change oversight is at the Board level. Specific oversight of certain aspects of the Company's response to climate change is delegated to the Board, its Governance, Safety and Sustainability Committee (GSSC), Audit, Finance and Risk Committee (AFRC), and Investment Performance Committee (IPC).

Meeting quarterly, the GSSC assists the Board in monitoring and assessing compliance with climate change regulation and reporting. The GSSC receives management reports on changes in climate-related legislation and the potential impact of policy developments on TransAlta's business. The GSSC also supports the Board in overseeing Company-wide climate change strategies, policies and practices. The GSSC also reviews environmental protection guidelines, including with respect to GHG mitigation, and considers whether our environmental procedures are being implemented effectively.

The AFRC and IPC also play an important role in managing TransAlta's climate-related risks and opportunities. The AFRC assists the Board in overseeing the integrity of our consolidated financial statements and considers climate risks and opportunities related to our financial decision-making. The AFRC is also responsible for approving our Commodity and Financial Exposure Management policies and reviewing quarterly ERM reporting. The IPC considers and assesses risks related to capital investment projects, including overseeing climate risk assessments and mitigation plans.

The Board reviews and updates the Company's strategy annually. In 2024, the Board's strategic planning sessions included climate-related issues considering growth initiatives and strategies, capital allocation, policy development and other matters. Our Board is comprised of individuals with a mix of skills, knowledge and experience critical to our strategy success and business growth. In 2024, three of our 12 Board members identified environment/climate change among their top four relevant competencies. Given the breadth of experience and skills of each director, the Board skills matrix lists only the top four competencies of each director nominee, based on the Board's assessment and each director's self-evaluation. Criteria used to assess competence on climate-related issues include the director's knowledge of corporate responsibility practices and sustainable development practices, including as they pertain to climate change.

For further information regarding Board members competence on climate-related issues, refer to TransAlta's Management Proxy Circular.

Role of Senior Management

TransAlta's President and CEO maintains the highest level of oversight on climate-related issues at the executive level. Senior management of the Company, including our President and CEO, provide the Board with updates on climate-related risks and opportunities to inform business strategy, mitigate risk, and ensure alignment with TransAlta's GHG emissions reduction goals.

Our business units and corporate functions work closely together to support the executive team in understanding climate-related risks and opportunities, including legislative and regulatory developments. Our executive team reviews such risks and opportunities quarterly and reports to the GSSC and AFRC, as applicable.

At the business unit level, climate change risks are identified through our Total Safety Management System, asset management function and systems, energy and trading business, communication with stakeholders, active monitoring and participation in working groups.

Notably, we link our annual incentive plans (short-term incentive and long-term incentives) to our strategic goals. In 2024, our strategic goals included growing renewable energy and supporting our customers' sustainability goals to decarbonize through on-site renewable energy generation.

For further information on incentives for ESG performance, refer to the discussion on ESG-Linked Compensation in Building a Diverse and Inclusive Workforce section of this MD&A.

Climate Scenarios

In 2021, TransAlta conducted climate scenario analysis to understand risks and opportunities and assess our strategy's resiliency under several potential future climate scenarios. The analysis used scenarios from the International Energy Agency's (IEA) World Energy Outlook 2020, a large-scale simulation model designed to replicate how energy markets function. We used three scenarios: Stated Policies (STEPS); Sustainable Development (SDS); and Net-Zero Emissions by 2050 (NZE).

In STEPS, the energy system has no major additional climate and environmental policies enacted by government(s). STEPS assumes that carbon pricing continues in Canada while no carbon price is set in the U.S. or Australia. STEPS also assumes that the power sector reduces emissions by 45 per cent by 2040 while natural gas generation capacity increases. Finally, STEPS is limited to the deployment of commercial-ready technologies, including wind and solar.

In SDS, the goals of the Paris Agreement (2015) are achieved, resulting in net-zero emissions by 2070. The SDS assumes a rapid increase in clean energy policies and investments that position the energy system to also achieve key UN SDGs. In SDS, all current net-zero pledges are achieved and there are extensive efforts to reduce emissions. SDS assumes that carbon pricing continues in Canada and is set in the U.S. and Australia. It also assumes that the power sector reduces emissions by 90 per cent by 2040 while natural gas capacity remains stable into 2030 and declines toward 2040. Finally, SDS assumes that beyond wind and solar, the energy system relies on batteries, storage and some level of carbon capture, utilization and storage (CCUS) and hydrogen.

NZE represents a pathway for the global energy sector to achieve net-zero emissions by 2050. This scenario also assumes key energy-related SDGs are achieved through universal energy access by 2030 and major improvements in air quality.

NZE is built upon the idea that a global increase in electrification supports the journey to net-zero. It assumes that an aggressive carbon price is set in Canada, the U.S. and Australia. It also assumes the power sector reaches net-zero emissions by 2035 in advanced economies while natural gas capacity is stable to 2030 and declines significantly into 2040. Like the SDS, NZE assumes that beyond wind and solar, the energy system relies on batteries, storage and some level of CCUS and hydrogen.

In 2024, we reviewed the findings from the climate scenario analysis and updated the management response accordingly.

Key Climate Scenario Findings

In 2021, TransAlta used climate scenarios from the IEA World Energy Outlook 2020 to analyze the resiliency of our business and determine specific risks and opportunities for our individual assets. All three scenarios present opportunities for TransAlta's growth related to renewables, storage solutions and ancillary services. Our scenario analysis at that time determined that our wind and solar assets had the highest prospects for growth. Under all scenarios, hydro remains a valuable asset as it allows for expansion to include storage.

Findings outlined below may not reflect currently available climate scenarios or policy frameworks. We continue to monitor climate-related risks and opportunities that may impact our business over time. For further information, refer to the Managing Climate Change Risks and Opportunities section in this MD&A.

The following sections highlight TransAlta's top risks, opportunities and management response across all scenarios.

Top Identified Climate-Related Risks by Scenario (2021)

	Increased clean energy competition	Decreased demand of natural gas electricity	Increased operational costs
Description	Subsidies/funds available for clean energy transition increase as governments aim to grow installed capacity of renewables to meet rising electricity demand and compensate for the closure of carbon-intensive power plants. In Canada, it is expected that major grid decarbonization investments will flow into Alberta as most other provincial markets are heavily regulated and/or are already low carbon. This will increase competition in the wholesale electricity market, making a large part of the generating fleet frequently bid at zero, driving down the average price of dispatched electricity. Simultaneously the cost of renewables, expected to decline across all scenarios, decreases the capital barrier to entry. These combined factors will increase competition for TransAlta. The IEA scenarios do not provide clear indication of electricity pricing and how it can be affected by increased competition. As such, this remains a point of uncertainty. Some structural market changes may be required to guarantee returns for power generators and successfully decarbonize the grid.	Demand for power from natural gas declines as the market shifts towards cleaner power with gas shifting to a reliability backstop role. An additional decline from Canadian oil and gas customers can occur as oil production levels drop under NZE and SDS. The transition to a lower-carbon world will likely result in volatility and market uncertainty. Natural gas power may be necessary to provide power in the transition if the pace of decarbonization is slower than expected in the scenarios or if grid-scale storage solutions do not develop/commercialize as modelled. In these cases, with coal phased out, natural gas facilities will be relied on for baseload generation. This means that natural gas facilities may still play a role for a smooth and efficient energy transition. Optimization of natural gas facilities is required, and additional investments need to be assessed with caution to consider the pace of decarbonization and consequent risk of decreased demand for natural gas power.	Carbon price increases the cost of natural gas operations. Additional mandated emissions reductions could force remaining plants to invest in technologies like CCUS, further increasing the operating costs for natural gas plants. Natural gas facilities in the U.S. and Western Australia face less risk compared to assets in Alberta as they are contracted and can pass down carbon costs to their clients. Current and anticipated regional carbon pricing monitoring is required to plan and assess increases in operational costs and impacts on new projects and investments.

	Increased clean energy competition	Decreased demand of natural gas electricity	Increased operational costs
NZE	By 2040, renewables are expected to comprise over 85 per cent of the total electricity generation in the regions where we operate. This surge in renewables will increase competition and drive electricity pricing down depending on availability and the cost of energy storage. The change in electricity prices and increased market uncertainty are expected to impact our profits.	The share of natural gas electricity generation is expected to decline over 50 per cent in the regions in which we operate by 2040 compared to 2019 levels. This lower demand for natural gas power is expected to impact our natural gas facilities if no management responses are implemented.	Higher operational costs driven by an increase in carbon price to US$205/tonne CO_2e by 2040 in all our operating regions (advanced economies under IEA scenarios) and lower operational capacity is expected to impact the profits from our natural gas facilities.
SDS	Fewer subsidies/funds are expected under this scenario compared to NZE. However, renewable costs will still decline approximately 10 per cent in wind and 55 per cent in solar by 2040 compared to 2019 levels. This decline with some level of subsidy will increase competition and potentially decrease electricity prices, which is expected to impact our profits.	Natural gas electricity generation still falls over 50 per cent in North America while remaining flat in Western Australia by 2040 compared to 2019 levels. Demand for natural gas power is expected to decrease at a slower pace than under NZE. This could potentially impact our natural gas facilities if no management responses are implemented.	Increase in operational costs would happen at a slower rate compared to NZE but carbon costs are still expected to reach US$140/tonne CO2e by 2040 in all of our operating regions. This could potentially impact the operational capacity and profits from our natural gas facilities, depending on the ability to pass carbon prices on through our contracts.
STEPS	While minimal subsidies are expected and the cost of entry will not decline at the same rate as SDS or NZE, renewable costs are still expected to decline approximately eight per cent in wind and 45 per cent in solar by 2040 compared to 2019 levels. This will still cause an increase in competition that is expected to be offset by additional electricity demand and therefore it is not expected to impact our profits.	Natural gas electricity generation is expected to increase over 15 per cent in the regions in which we operate by 2040 compared to 2019 levels. These changes are not expected to affect our natural gas facilities.	Operational costs are not expected to significantly increase under this scenario as only Canada is expected to adopt a carbon price in 2040.
Management response	Navigating uncertainty around market dynamics (structure, pricing and competition), government policies and planning is critical for TransAlta. We use hedging and PPAs to reduce pricing-related risks. See more details of our strategy and risk management under the Climate Strategy section and the Managing Climate Change Risks and Opportunities section of this MD&A.	As concerns regarding grid reliability and demand increase, we have increased our focus on optimizing our gas facilities to maximize value and cash flows and to support future renewables and storage growth. Our converted natural gas units' CO_2 intensity is approximately 57 per cent less than coal generation. Repurposing the coal facilities rather than decommissioning them reduces the cost and emissions associated with new construction and aligns with the UN SDGs, specifically "Goal 9: Industry, Innovation and Infrastructure." In parallel, we plan to achieve a 100 per cent portfolio mix of renewables and natural gas by the end of 2025.	We have taken significant steps to reduce our carbon footprint. Since 2015, we have reduced scope 1 and 2 GHG emissions by 70 per cent. By 2026, we have a commitment to reduce scope 1 and 2 GHG emissions by 75 per cent from 2015 base year and have a target to achieve net-zero emissions by 2045.

Top Identified Climate-Related Opportunities by Scenario (2021)

	Renewables become major energy source	New technology development
Description	Opportunities to grow the renewable fleet exist across all scenarios. Renewable assets (hydro, wind, solar) are expected to become the default form of generation with demand for power from these types of assets increasing. Hydro is likely to grow in value given increased renewables penetration and the need for reliable zero-emitting generation. This can make hydroelectric power a stronger source of baseload electricity in many regions. The decreasing cost of renewables also facilitates the growth of a renewable fleet, especially under NZE and SDS.	Opportunities for the development of battery or hydroelectric storage systems and ancillary services exist across all scenarios as renewable energy continues to penetrate the grid. Developments in these areas are required to keep electricity flowing when the renewables in a region are not producing. Storage is anticipated to play an especially important role in the energy transition. Cost-competitive battery storage enables greater adoption of renewables.
NZE	A growth of renewable electricity generation of approximately 950 per cent is expected by 2040 compared to 2019 levels. This results in renewables comprising more than 85 per cent of the electricity generation in the regions in which we operate. The transition of hydro to baseload capacity is expected to create upside for TransAlta. An increase in TransAlta's renewable capacity and demand are expected to enable growth and higher revenues.	Increased revenues through access to new and emerging markets are expected to enable growth and higher revenues under NZE. With more than 85 per cent of electricity in areas in which we operate made up of renewables, there will be big steps forward in storage and ancillary services technologies. Storage capacity is expected to grow to approximately 250 GW in the U.S. by 2040.
SDS	A growth of renewable electricity generation of approximately 550 per cent is expected by 2040 compared to 2019 levels. This results in renewables comprising more than 75 per cent of the electricity generation in the regions in which we operate. An increase in TransAlta's renewable capacity and demand are expected to enable growth and higher revenues.	Increased revenues through access to new and emerging markets are expected to enable growth and higher revenues under SDS. A lower share of renewables than in NZE will allow swing production to remain present; however, growth in ancillary and storage capacity will still be needed to support the market. Storage capacity is expected to grow to approximately 110 GW in the U.S. by 2040.
STEPS	STEPS growth is muted relative to the other scenarios but still sees a growth of renewables of 280 per cent by 2040 compared to 2019 levels. This growth will allow approximately 50 per cent of electricity generation to come from renewables in areas in which we operate by 2040. An increase in TransAlta's renewable capacity and demand are expected to enable growth and higher revenues.	Access to new and emerging markets would be limited under this scenario compared to NZE and SDS. While growth in renewables is expected, the need for new technologies is not a necessity in this market and may not be profitable. Therefore, our revenues are not expected to be affected.
Management response	Our renewable energy commitment began more than 100 years ago when we built the first hydro assets in Alberta, which still operate today. We now operate 60 renewable facilities across Canada, the U.S. and Western Australia. Our strategy is focused on the operation and/or repurposing of our existing assets (wind, hydro, solar, gas, storage and coal) and the development of renewable energy, storage and natural gas generation for reliability. From 2000 to 2024, we increased our nameplate renewables capacity from approximately 900 MW to over 3,600 MW. Today, TransAlta is one of the largest producers of wind power in Canada and the largest producer of hydro power in Alberta.	To address and mitigate the challenges of renewable energy intermittency, we continue to invest in battery storage. In 2020, we launched WindCharger, a "first of its kind in Alberta" battery storage project that stores energy produced by our Summerview II wind facility and discharges electricity into the Alberta grid during system supply shortages. Further, in 2023, we completed the Northern Goldfields solar project in Western Australia, which provides solar electricity supported with a battery energy storage system and will support BHP Nickel West in meeting its emissions reduction targets. In 2024, TransAlta launched a project with Atlas Power Technologies Inc. for a hybrid hydro supercapacitor energy storage system, expected to be the first of its kind in North America. The project is complementary to an existing hydro facility that augments the power plant's response time and the capability to address frequency response needs.

NZE: The most significant risks include increased competition, decreased demand for natural gas and increased operational costs due to increased carbon pricing and emissions reduction mandates. The most significant opportunities include a shift toward renewables as the default energy source and new technology developments, including battery storage systems and ancillary services. It is worth noting that there are additional risks and opportunities for TransAlta under NZE. For example, changes in how energy market services are offered could positively or negatively impact our business. Further, as carbon credit policies evolve, so will our ability to use credits. Lastly, as renewables become the primary energy source, a rethinking of ancillary services will be necessary but could create significant opportunities for TransAlta.

SDS: The risks and opportunities remain the same under SDS as NZE; however, the impacts are reduced as market changes are slower and less extreme. Renewables still become the primary electricity source and there are new technology opportunities, particularly in batteries. Natural gas electricity demand still declines by 2040. Carbon pricing exists in the U.S. and Australia, but the price is reduced compared to NZE. Lastly, a reevaluation of ancillary services still presents an opportunity for TransAlta.

STEPS: Under STEPS, renewable generation sees significant growth but does not become the predominant energy source. Implementing new technologies is much slower and the demand for batteries is reduced. The demand for natural gas electricity does not decline and there are no large-scale market changes making services, pricing and ancillary services more stable. This removes the risk associated with natural gas electricity demand but eliminates the opportunity for growth in ancillary services. Physical risks become more relevant under this scenario than transitional risks.

The findings from the climate scenarios work alongside our sustainability metrics and targets to inform the evolution and resiliency of our Company's strategy and financial planning, risk management, opportunity assessment and planning for uncertainty.

Managing Climate Change Risks and Opportunities

We actively monitor and manage climate-related risks through our Company-wide ERM processes. In 2021, we used a climate scenario analysis to review specific risks. As previously mentioned, climate change risks and opportunities are addressed at each of the Board, executive and management, business unit levels and through our corporate functions. The business units and corporate functions work closely together and provide information on risks and opportunities to management, the executive team and the Board.

Climate change risks at the asset or business unit level are identified through our Total Safety Management System, asset management function and systems, energy and trading business, communication with stakeholders, active monitoring and participation in working groups. All identified material risks are added to our ERM register and scored based on likelihood and impact. We do not consider risks in isolation and major risks are the focus of management response and mitigation plans. Further discussion can be found in Reporting in the Governance and Risk Management section of this MD&A.

We divide our climate change risks into two major categories as per IFRS S2 and TCFD guidance: (i) risks related to the transition to a lower-carbon economy; and (ii) risks related to the physical impacts of climate change.

Transition Risks to a Lower-Carbon Economy

We actively aim to understand and manage the impact of climate change on our business. In 2024, we updated the transition risks outlined below.

Policy and Legal Risks

Changes in current environmental legislation have a potentially significant impact upon our business and operations in Canada, the U.S. and Australia.

For a more detailed assessment of policy and regulatory risks, refer to the Governance and Risk Management section of this MD&A.

Canada

The Government of Canada has set objectives for carbon emissions reductions, including a 45 to 50 per cent national emissions reduction over 2005 levels by 2035, a net-zero electricity grid by 2035 and a net-zero national economy by 2050. The current government plans to rely on several policy tools to achieve its emissions objectives, including but not limited to carbon pricing, emissions performance regulations, funding for industrial energy transition, and incentives for consumers.

Canada's provinces have jurisdiction over their respective electricity sectors and play an important role in setting carbon pricing policy and emissions performance standards, subject to the federal government's authority to set national carbon pricing standards. Jurisdictional responsibilities between the federal and provincial governments enable both levels of government to implement policies that impact our sector. Leadership changes at either level of government can influence policy direction.

Risks

- Changes in carbon pricing and emissions performance regulations may impact TransAlta's generation fleet in Canada as governments may change policy stringency in conjunction with climate targets.
- Government funding for industrial energy transition may create out of market incentives for competing generation.
- Regulatory incentives, including emissions reduction crediting, may create out of market incentives for competing generation.
- Lack of federal/provincial coordination with respect to climate policy and regulation may lead to investment uncertainty.

Opportunities

- Independent estimates suggest that achieving Canada's current climate targets will require a minimum of twice Canada's current non-emitting generation. Further, we continue to see strong private sector demand for contracted renewable electricity generation to meet corporate sustainability goals.
- Government funding to support the development of innovative technology to reduce emissions from the electricity sector offers TransAlta the potential opportunity to gain project support to grow its energy storage fleet.
- Government support for industrial electrification will grow the electricity load over time and create new opportunities for electricity generation.

Management Response

- We believe that TransAlta's corporate strategy positions our Company to meet the demand for renewable and dispatchable generation driven by customers and government policy.
- We are focused on developing and acquiring contracted assets that provide long-term certainty with respect to revenue and eligibility for government incentive programs as applicable. TransAlta actively assesses available government renewable energy tax legislation and programs to maximize, wherever possible, access to project incentives.
- Our diversified portfolio and contracted growth reduces the proportional Company exposure to potential policy and regulatory decisions that negatively impact natural gas generation.
- Our coal-to-gas facilities fit within government plans to continue providing reliable and competitively priced electricity for consumers and industry.
- Our remaining natural gas facilities (non-coal-to-gas) operate under contract, reducing TransAlta's exposure to changes in carbon pricing.
- We engage with the federal and provincial governments in Canada to inform and influence policy development to ensure that our generating fleet continues to serve our customers.
- We actively work, both directly and through industry associations, to encourage governments to adopt a level playing field within funding and crediting programs so that all new emerging technology projects receive equitable government incentives and funding.
- We engage with all relevant Canadian governments to seek policy alignment across carbon pricing and regulatory and funding programs to create the greatest possible degree of investment certainty.

United States

President Trump was elected on Nov. 4, 2024. It is expected that the U.S. Government will reduce carbon emission reduction objectives in 2025 following the inauguration. Currently, the Inflation Reduction Act of 2022 remains in force and aims to reduce U.S. carbon emissions by 40 per cent by 2030 from 2005 levels. The U.S. does not have a national carbon pricing regime but does offer federal incentives for renewable generation and energy storage.

State and regional renewable and climate policies have a significant impact on the pace of energy transition in the country, with several jurisdictions maintaining renewable portfolio standards and/or carbon pricing regimes. Similar to Canada, independent estimates suggest that the U.S. will require substantial growth in zero-emissions generation to meet its national, state and regional climate targets.

Risks

- TransAlta operates two thermal generating facilities in the U.S. that could be subject to policy changes, but we believe that our risk exposure is low due to existing agreements and contracts associated with these facilities (refer to Management Response below).
- Potential changes to federal wind permitting could pose risks for new wind development projects.

- Federal incentives for clean energy that are available today are expected to maintain competition in renewables and energy storage.

Opportunities

- Achieving government and private sector sustainability commitments will require sustained growth in zero-emissions electricity generation over the coming decades. TransAlta remains focused on providing renewable electricity as a core component of a balanced energy portfolio to contracted customers in a manner that is aligned with federal, state and private sector goals.
- Strong customer demand to meet low-carbon energy and reliability needs present opportunities for TransAlta.
- U.S. tax incentive programs offer significant support for new renewable and energy storage projects, making the U.S. an attractive growth market.

Management Response

- TransAlta's single coal unit in Washington State is subject to a retirement agreement with the state government that exempts the facility from any carbon regulation before its end of life in 2025. TransAlta's cogeneration unit at Ada operates under a contract that reduces the Company's exposure to policy risk.
- The Company remains focused on developing and acquiring contracted assets that provide long-term certainty with respect to revenue.
- TransAlta will continue to assess government policy changes related to our business under the new U.S. administration.

Australia

The Australian Government has a 43 per cent national emissions reduction target over 2005 levels by 2030 and a goal to achieve a net-zero national economy by 2050. Decarbonization efforts have been centered on funding clean technologies, upgrading the electricity grid to support more renewables, regulating and reporting of GHG emissions, and incentivizing zero-emissions vehicle adoption. Large GHG emitters are required to reduce their scope 1 emissions under the Australian Government's National Safeguard Mechanism (SGM). While the government has made recent changes to the SGM, these changes are not expected to have a material impact on TransAlta's assets. Australian state governments have all adopted net-zero goals and a number of states have interim targets for 2030 and 2040. These state policies are driving demand for zero-emissions electricity and energy storage.

Risks

- TransAlta's Western Australian natural gas facilities may face policy risk related to changes in government policies but we believe that we remain well positioned to mitigate those risks (refer to Management Response below).

Opportunities

- The Company remains focused on maintaining renewable and dispatchable electricity generation in Western Australia and other markets. Government policies and funding programs are generally supportive of the types of projects contemplated within TransAlta's strategy.
- Strong corporate demand for renewable electricity solutions in Australia's natural resource sectors present opportunities for TransAlta to leverage its existing expertise to help customers meet regulatory requirements and reach their decarbonization objectives.

Management Response

- TransAlta's assets are predominantly contracted with an ability to pass through carbon compliance costs and serve remote industrial load. As a result, the Company faces reduced policy risk.
- The Company continues to deliver renewable electricity solutions to natural resource customers in Western Australia. Our growing suite of technologies, including renewables and energy storage, positions us to provide contracted solutions to customers focused on the need for reliable and sustainable energy.
- TransAlta also continues to assess opportunities to grow our renewable energy generation in alignment with Australia's national and state climate goals.

Technology Risks

Technological changes to support the low-carbon transition present both risks and opportunities for TransAlta. We evaluate existing and emerging impacts of technology through our Energy Innovation team and our ERM process. Examples of technology risks and opportunities include infrastructure changes and digitization combined with greater adoption of energy efficiency (less use of our end product). Cost-competitive battery storage will enable greater adoption of renewables and a shift to a distributed power generation model. We continue to evaluate battery storage for its financial viability while monitoring the potential impact battery technology could have on natural gas power generation. In 2020, we completed our first battery storage (10 MW) project at one of our wind facilities in Southern Alberta. In 2023, we delivered a hybrid system of solar with battery storage (48 MW) in Western Australia. We continue to investigate the possibility of battery storage at our other facility locations. Our teams continuously adopt improved technology at each of our new developments, which helps protect shareholder value and maintain reliable and affordable electricity delivery.

We believe that we are well-positioned to take advantage of technological opportunities in storage through hydro

and/or battery power, as well as advancements in renewable technologies. We will continue monitoring new technologies such as storage, hydrogen and CCUS for future deployment.

For further information on technology and innovation, refer to the Enabling Innovation and Technology Adoption section of this MD&A.

Market Risks

Our major market risks are associated with our natural gas facilities and specifically carbon pricing which could impact our operating costs. We actively monitor market risks through our energy marketing and asset optimization teams and our ERM process. Further, our corporate functions apply regionally specific carbon pricing, both current and anticipated, as a mechanism to manage future risks of uncertainty in the carbon market. To simultaneously manage our risks and leverage market opportunities, we continue operating our hydro, wind and solar facilities and evaluating fleet growth opportunities.

Our renewable fleet makes our overall portfolio more resilient to climate risk, provides increased flexibility in generation and creates incremental environmental value through environmental attributes. Lastly, we recognize the opportunity to grow our ancillary services, such as systems support, providing flexibility and reliability to the grid.

Reputation Risks

Negative reputational impacts, including revenue loss and a reduced customer base, are evaluated through our ERM process. In the past, we experienced negative reputational impacts due to our coal operations. We believe that our transition path away from coal mitigates this reputational risk. As consumer trends move in favour of renewable electricity, we are investing in a diversified mix of renewable generation and optimizing our existing natural gas fleet. We believe that natural-gas-fired generation enables the energy transition by ensuring the reliability of the electricity grid. We continue to actively monitor and manage reputational risks by delivering reliable and responsible power solutions.

Physical Risks of Climate Change

As we learn more about the physical risks associated with climate change, we continue to consider acute and chronic risks that could significantly impact our operations. We continue to investigate the physical impacts of climate change on our operating assets.

Acute Physical Risks

We have operating assets in three countries and varied geographic locations, many of which could be impacted by extreme weather events. These events can impact our operations and give rise to risks. Due to the nature of our business, our earnings are sensitive to seasonal weather variations. Variations in winter weather affect the demand for electrical heating requirements while variations in summer weather affect the demand for electrical cooling requirements. These variations in demand translate into spot market price volatility. Variations in precipitation also affect water supplies, which in turn affect our hydroelectric assets. Also, variations in sunlight conditions can have an effect on energy production levels from our solar facilities.

Our generation facilities and their operations are exposed to potential damage and partial or complete loss resulting from environmental disasters (e.g., floods, strong winds, wildfires, earthquakes, tornados and cyclones), equipment failures and other events beyond our control. Climate change can increase the frequency and severity of these extreme weather events. The occurrence of a significant event that disrupts the operation or ability of the generation facilities to produce or sell power for an extended period, including events that preclude existing customers from purchasing electricity, could have a material adverse effect. In certain cases, there is the potential that some events may not excuse us from performing our obligations pursuant to agreements with third parties. The fact that several of our generation facilities are located in remote areas may make access for repair of damage difficult.

We continuously evaluate the potential impact of acute climate change on our business. For example, our gas facility at the South Hedland, Australia, is built with climate adaptation in mind. We designed the facility to withstand a category 5 cyclone (the highest cyclone rating). We have mitigated the risk of floods that can occur in the area by constructing the facility above normal flood levels. In 2019, a category 4 cyclone hit this facility and did not impact operations. We were able to continue generating electricity through the storm despite widespread flooding and the shutdown of the nearby port. In Canada, since the 2013 floods in Southern Alberta, we have implemented projects that increase the resilience of our hydro facilities to severe climate events. We have also modified operations at several of our facilities as per an agreement with the Government of Alberta. This reduces flood risk in the spring while also recognizing the potential for increased droughts as a result of climate change in the future. TransAlta continues to participate in multi-stakeholder groups developing options for climate resiliency across Southern Alberta.

Chronic Physical Risks

Chronic physical risks refer to longer-term shifts in climate patterns that may cause sea level rise, chronic heat waves, changes in precipitation patterns and extreme variability in weather patterns.

These variations in weather could have an impact on our generating assets. Ice can accumulate on wind turbine blades in the winter months. The accumulation of ice on

wind turbine blades depends on a number of factors, including temperature and ambient humidity. Accumulated ice can have a significant impact on energy yields and could result in the wind turbine experiencing more downtime. Extreme cold temperatures can also impact the ability of wind turbines to operate effectively and this could result in more downtime and reduced production. In addition, climate change could result in increased variability to water flow or wind patterns that could impact our hydro and wind businesses and associated revenue generation.

Climate Change Metrics and Targets

Metrics and Targets

TransAlta has established climate-related goals and targets with reference to the UN SDGs. Performance against our 2024 climate-related targets is outlined below and excludes the acquisition of Heartland Generation on Dec. 4, 2024. Target year means by Dec. 31 of that year.

Renewable Energy Growth

Sustainability target	Develop new renewable projects that support our customers' sustainability goals to achieve both long-term power price affordability and carbon reductions.(1)	No further coal generation; 100 per cent of our owned net generation capacity from renewables and gas.
Target year	2024	2025
Progress	Since 2021, we have added over 800 MW of new capacity through renewable projects such as Windrise (206 MW), Garden Plain (130 MW), Northern Goldfields Solar (48 MW), White Rock (302 MW) and Horizon Hill (202 MW).	In 2024, our owned net generation capacity from renewables and gas represented approximately 90 per cent of our total 6,425 MW owned net generation capacity. In 2021, we achieved full phase-out of coal in Canada. In the U.S., we plan to cease coal-fired generation at our Centralia plant by Dec. 31, 2025.
UN SDG alignment	Target 7.2: "By 2030, increase substantially the share of renewable energy in the global energy mix".	Target 7.1: "By 2030, ensure universal access to affordable, reliable and modern energy services".

(1) This includes the construction of new renewable projects (hydro, wind and solar).

GHG Emissions Reduction

Sustainability target	By 2026, achieve a 75 per cent reduction of scope 1 and 2 GHG emissions from a 2015 base year.	By 2045, achieve net-zero for 100 per cent of TransAlta's scope 1 and 2 GHG emissions.
Target year	2026	2045
Progress	We are on track to achieve our target of 75 per cent scope 1 and 2 GHG emissions reductions by 2026. Since 2015, we have reduced scope 1 and 2 GHG emissions by 22.7 MT CO_2e or 70 per cent.	Since 2005, we have reduced our scope 1 and 2 GHG emissions by 32 million tonnes (MT) of CO_2e or a 77 per cent reduction, proudly representing approximately 11 per cent of Canada's Paris Agreement 2030 decarbonization target(1). We believe that our corporate strategy supports achieving our net-zero target.
UN SDG alignment	Target 13.2: "Integrate climate change measures into national policies, strategies and planning".	Target 13.2: "Integrate climate change measures into national policies, strategies and planning".

(1) In 2005, TransAlta's estimated scope 1 and 2 GHG emissions were 41.9 MT of CO_2e, which did not receive independent limited assurance. Canada's Paris Agreement 2030 decarbonization target assumed 293 MT of CO_2e or a 40 per cent reduction from a 2005 baseline of 732 MT of CO_2e.

TransAlta's target to reduce 75 per cent of our scope 1 and 2 GHG emissions by 2026 from a 2015 base year is estimated to align with the electricity sector decarbonization pathway to limit global warming to 1.5°C, as one of the Paris Agreement goals.

GHG Disclosures

Scope 1 and 2 Emissions

Scope 1 emissions are the direct emissions from owned or controlled sources. Scope 2 emissions are indirect emissions from the generation of purchased energy. TransAlta's scope 1 and 2 GHG emissions are calculated using different methodologies depending on the technologies available at our facilities. Emissions data has been aligned with the "Setting Organizational Boundaries: Operational Control" methodology set out in The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard developed by the World Resources Institute and the World Business Council for Sustainable Development. We report emissions on an operation control basis, which means we report 100 per cent of emissions at the facilities that we operate.

We compile our corporate GHG inventory using our business segment GHG calculations. As a result, emission factors and global warming potentials used in our GHG calculations can vary due to difference in regional compliance guidance. Applying harmonized global warming potentials across our fleet would result in a minor variance to our overall calculated GHG totals.

Our GHG data is reported to a number of different regulatory bodies throughout the year for regional compliance and, as a result, may incur minor revisions as we review and report data annually. Any historical revisions will be captured and reported in future disclosure. As per the Kyoto Protocol, GHGs include carbon dioxide, methane, nitrous oxide, sulphur hexafluoride, nitrogen trifluoride, hydrofluorocarbons and perfluorocarbons. Our exposure is limited to carbon dioxide, methane, nitrous oxide and a small amount of sulphur hexafluoride. The majority of our estimated GHG emissions result from carbon dioxide emissions from stationary combustion from coal and natural-gas-powered generation. Methane emissions from our operations are mainly due to incomplete combustion of natural gas from natural-gas-powered plants and there are no fugitive methane emissions associated with our operations. In 2024, methane emissions were 0.5 per cent of our total emissions.

The following tables detail our GHG emissions by scope, business segment and country in million tonnes of CO_2e. Some values do not sum to the indicated total due to rounding of tabulated emissions. Zeros (0.0) indicate truncated values.

Year ended Dec. 31	2024	2023	2022
Scope 1	**9.5**	10.9	10.2
Scope 2	**0.1**	0.1	0.1
Total scope 1 and 2 GHG emissions	**9.6**	10.9	10.3

Year ended Dec. 31	2024	2023	2022
Hydro	**0.0**	0.0	0.0
Wind and Solar	**0.0**	0.0	0.0
Gas	**6.3**	6.4	6.3
Energy Transition	**3.2**	4.5	4.0
Corporate and Energy Marketing	**0.0**	0.0	0.0
Total scope 1 and 2 GHG emissions	**9.6**	10.9	10.3

Year ended Dec. 31	2024	2023	2022
Australia	**0.9**	1.0	0.9
Canada	**5.4**	5.3	5.2
United States	**3.3**	4.6	4.1
Total scope 1 and 2 GHG emissions	**9.6**	10.9	10.3

In 2024, our GHG emissions (scope 1 and 2) were 9.6 million tonnes as a result of normal operating activities. This represents a 12 per cent decrease from 2023. As a result, in 2024 our scope 1 and 2 GHG emissions intensity decreased to 0.35 tCO_2e/MWh from 0.41 tCO_2e/MWh in 2023. TransAlta plans to cease generation from our single remaining coal unit by the end of 2025, which will further reduce the Company's emissions.

TransAlta sells the environmental attributes generated from our renewable energy facilities and does not subtract this amount from our total GHG emissions (scope 1 and 2).

However, it should be noted that TransAlta's customers are reporting GHG emissions reductions using our renewable energy assets, projects and operations.

GHG emissions are verified to a level of reasonable assurance in locations in which we operate within a carbon regulatory framework. Any historical revisions to GHG data will be captured and reported in future disclosure. The majority of our GHG emissions result from carbon dioxide emissions from stationary combustion from coal- and natural-gas-fired generation.

The following table highlights our scope 1 and 2 GHG emissions reductions since 2015 and our targeted emissions in 2026 in million tonnes of CO_2e. The actual GHG emissions for the Company in 2026 will vary from that presented below depending on, among other things, the growth of the Company, including its on-site generation business.

Year ended Dec. 31	2026 (forecast)	2024	2015
Total scope 1 and 2 GHG emissions	**8.1**	9.6	32.2

Scope 3 Emissions

Scope 3 emissions are all indirect emissions (not included in scope 1 or 2) that occur in the value chain of the reporting company, including both upstream and downstream emissions. TransAlta's scope 3 emissions are calculated using methodologies consistent with the GHG Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard (Scope 3 Standard) and with reference to the additional guidance provided in the GHG Protocol Technical Guidance for Calculating Scope 3 Emissions (Scope 3 Guidance) developed by the World Resources Institute and the World Business Council for Sustainable Development.

TransAlta's scope 3 emissions include the indirect GHG emissions resulting from activities in our value chain but outside of our operational control. Of the 15 categories described in the GHG Protocol Scope 3 Guidance, four are not relevant to our business and, therefore, are not included in the calculation: Category 8: Upstream leased assets, Category 12: End-of-life treatment of sold products, Category 13: Downstream leased assets, and Category 14: Franchises.

In 2024, we achieved our target to verify and disclose 80 per cent of TransAlta's scope 3 emissions by 2024. Of the 15 categories described in the GHG Protocol Scope 3 Guidance, five are the most relevant to our business and together they accounted for 93 per cent of our total scope 3 emissions of approximately 3.7 million tonnes of CO_2e in 2024. They include Category 1: Purchased goods and services, Category 2: Capital goods, Category 3: Fuel and energy-related activities, Category 11: Use of sold products, and Category 15: Investments. These emissions received limited assurance by a third-party provider.

The following table details our total scope 3 GHG emissions in million tonnes of CO_2e. Some values do not sum to the indicated total due to rounding of tabulated emissions. Zeros (0.0) indicate truncated values.

Year ended Dec. 31	2024	2023	2022
Category 1: Purchased goods and services[1]	**0.0**	0.0	0.0
Category 2: Capital goods[2]	**0.0**	0.1	0.1
Category 3: Fuel and energy-related activities[3]	**1.0**	1.0	1.0
Category 11: Use of sold products[4]	**0.6**	0.7	0.6
Category 15: Investments[5]	**1.8**	1.7	1.8
Other relevant categories[6]	**0.2**	0.3	0.3
Total scope 3 GHG emissions	**3.7**	3.7	3.8

(1) Category 1: Purchased goods and services includes emissions associated with the purchase of goods and services described as operating expenses.

(2) Category 2: Capital goods includes emissions associated with the purchase of capital goods and services described as capital expenditures.

(3) Category 3: Fuel and energy-related activities includes emissions associated with the extraction, production of all fuels consumed and midstream transportation of natural gas (pipeline). Excludes the emissions associated with electricity purchased from the grid as they have been accounted for in our scope 2 GHG emissions, but accounting for the transmission and distribution losses.

(4) Category 11: Use of sold products includes emissions associated with natural gas combustion during electricity production where the sales and delivery of physical natural gas occur.

(5) Category 15: Investments includes scope 1 and 2 GHG emissions (on an equity basis) from our assets that are owned (as a joint venture or other ownership structure) but not operated by TransAlta.

(6) Other relevant categories include Category 4: Upstream transportation and distribution, Category 5: Waste generated in operations, Category 6: Business travel, Category 7: Employee commuting, Category 9: Downstream transportation and distribution, and Category 10: Processing of sold products. These emissions were estimated based on best available information and did not receive imited assurance by a third-party provider.

Avoided Emissions

In 2024, production from renewable assets resulted in the avoidance of approximately 2.8 million tonnes of CO_2e for our customers. TransAlta's avoided emissions are defined as the sum of the displaced emissions by our renewable assets in the jurisdictions where we operate.

The value is calculated as the product of the generation of electricity obtained from a renewable source (hydro, wind and solar) and the specific CO_2 emissions intensity from the grid of the jurisdiction in which we operate. Avoided emissions increased in 2024 compared to 2023 primarily due to an increase in renewable fleet generation.

The following table highlights our avoided emissions in million tonnes of CO_2e.

Year ended Dec. 31	2024	2023	2022
Total GHG emissions avoided	**2.8**	2.3	2.7

Sustainable Finance

Sustainable finance is the process of taking due account of ESG considerations (e.g., climate change, biodiversity, human rights, etc.) when making investment decisions. Sustainable finance is a key pillar of TransAlta's Climate Transition Plan. This means that we may choose to utilize pools of capital available to sustainable economic activities and projects to finance our energy transition.

TransAlta deploys green and sustainable financing to build our renewable energy fleet. This supports our goal to deliver on our customers' needs for renewable electricity. Since 2020, we have issued $726 million in green bonds and converted our four-year, $2.0 billion revolving credit facility, into a sustainability-linked loan.

In 2022, TransAlta issued US$400 million ($533 million) in Senior Green Bonds, and an amount equal to the net proceeds from the bonds has been allocated to finance or refinance new and/or existing eligible green projects. The bonds were issued under TransAlta's Green Bond Framework, which aligns with the Green Bond Principles published by the International Capital Market Association. For further information, refer to Green Bond Framework in the Shareholder Information section of the Investor Centre on our website.

In 2021, TransAlta converted an existing $1.3 billion syndicated revolving credit facility into a sustainability-linked loan. The loan aligns the cost of borrowing to the Company's GHG emissions reductions and gender diversity targets. Sustainability-linked loans are any types of loan instruments and/or contingent facilities (such as bonding lines, guarantee lines or letters of credit) that incentivize the borrower's achievement of ambitious, predetermined sustainability performance objectives.

The summary below shows the carrying value of the issued green bonds and the total committed facility size of our ESG financial operations portfolio.

As at Dec. 31 (in millions of Canadian dollars)	2024	2023	2022
Green bonds [1]	**726**	684	703
Sustainability-linked loans	**1,950**	1,950	1,250

(1) Green bonds are related to the Senior Green Bonds issued in 2022.

Climate-Related Financial Metrics

The results of TransAlta's 2021 climate-related scenario analysis, aligning with a 1.5°C warmer world, have shown that opportunities to grow the renewable fleet exist across all scenarios and locations. Our revenue from renewable energy generation (hydro, wind and solar) in 2024 was $839 million (2023 – $902 million).

In 2024, our growth capital expenditures for renewable energy generation were $61 million (2023 – $630 million). In addition, TransAlta continues to invest in emerging abatement technologies and solutions. In 2024, our investments in low-carbon research and development were $8 million (2023 – $4 million).

In 2024, adjusted EBITDA from renewable energy generation was $632 million (2023 – $716 million). Our renewable fleet makes our overall portfolio more resilient to climate-related risks, provides increased flexibility in generation and creates incremental environmental value through environmental attributes. Our revenue in 2024 from environmental attribute sales was $79 million (2023 – $36 million).

The disclosure of TransAlta's financial metrics related to our climate-related risks and opportunities partially aligns with the IFRS S2 and TCFD recommendations.

A summary of our climate-related financial metrics is presented below.

Year ended Dec. 31 (in millions of Canadian dollars)	2024	2023	2022
Growth capital expenditures for renewable energy generation[1]	**61**	630	666
Renewable energy adjusted EBITDA[2]	**632**	716	860
Environmental and tax attributes revenue[3]	**79**	36	53
Renewable energy revenue[4]	**839**	902	1,014
Investments in low-carbon research and development[5]	**8**	4	12

(1) Growth capital expenditures include amounts deployed for growth projects and acquisitions related to renewable energy generation. This includes the Garden Plain wind project and the Northern Goldfields solar project, both completed in 2023, and the White Rock and Horizon Hill wind projects, both completed in 2024. This excludes the Mount Keith transmission expansion and Mount Keith west network upgrade projects.

(2) Adjusted EBITDA from renewable energy generation includes hydro, wind, solar and battery storage facilities. The renewable energy adjusted EBITDA is the total adjusted EBITDA of the Hydro and Wind and Solar segments. These items are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. During 2024 our adjusted EBITDA composition was amended to exclude the impact of Brazeau penalties and related provisions. Therefore, the Company has app ied this composition to all previously reported periods. Refer to the Additional IFRS Measures and Non-IFRS Measures and Segmented Financial Performance and Operating Results sections of this MD&A.

(3) Environmental and tax attributes revenue represents a full amount of hydro, wind and solar environmental credit sales, including intercompany sales.

(4) Adjusted revenue from renewable energy generation includes hydro, wind, solar and battery storage facilities. For details of the adjustments to revenues included in adjusted EBITDA refer to the Additional IFRS and Non-IFRS Measures section of this MD&A

(5) Investments in low-carbon research and development include our equity investment in Ekona Power Inc.'s (Ekona) Series A funding round and our four-year investment in EIP's Deep Decarbonization Frontier Fund 1 (the Frontier Fund).

Alignment with Climate-Related Disclosures Frameworks

The table below shows the partial alignment of our climate change management disclosure with TCFD and IFRS S2 recommendations.

TCFD Recommended Disclosures	Other Alignments	Location
Governance		
Describe the board's oversight of climate-related risks and opportunities	IFRS S2: 6	Oversight by the Board of Directors
Describe management's role in assessing and managing climate-related risks and opportunities	IFRS S2: 6	Role of Senior Management
Strategy		
Describe the climate-related risks and opportunities the organization has identified over the short, medium and long term	IFRS S2: 8-9	Key Scenario Findings
Describe the impact of climate-related risks and opportunities on the organization's businesses, strategy and financial planning	IFRS S2: 8-9	Climate Change Strategy, Key Climate Scenario Findings
Describe the resilience of the organization's strategy, taking into consideration different climate-related scenarios, including a 2°C or lower scenario	IFRS S2: 22-23	Climate Scenarios, Key Climate Scenario Findings
Risk management		
Describe the organization's processes for identifying and assessing climate-related risks	IFRS S2: 10	Climate Change Strategy
Describe the organization's processes for managing climate-related risks	IFRS S2: 24-25	Managing Climate Change Risks and Opportunities
Describe how processes for identifying, assessing and managing climate-related risks are integrated into the organization's overall risk management	IFRS S2: 24-25	Managing Climate Change Risks and Opportunities
Metrics and targets		
Disclose the metrics used by the organization to assess climate-related risks and opportunities in line with its strategy and risk management process	IFRS S2: 27-28	Climate Change Metrics and Targets
Disclose scope 1, scope 2 and, if appropriate, scope 3 greenhouse gas (GHG) emissions and the related risks	IFRS S2: 29-32	Climate Change Metrics and Targets
Describe the targets used by the organization to manage climate-related risks and opportunities and performance against targets	IFRS S2: 33-36	Climate Change Metrics and Targets

Enabling Innovation and Technology Adoption

TransAlta has been at the forefront of innovation in the power-generation sector since the early 1900s when we developed our first hydro facilities. We have been an early adopter and developer of wind technology, including the first commercial wind facility in Canada, and are now one of the largest wind generators in the country. In 2015, we made our first investment in solar technology in Massachusetts, in 2020, we installed the first utility-scale battery in Alberta and, in 2023, completed our first solar microgrid with battery energy storage system in Western Australia. This section covers manufactured and intellectual capital management partially in alignment with guidance from the IFRS's Integrated Reporting Framework.

Our Energy Innovation Team

In 2021, we established an Energy Innovation team to investigate, prioritize and deploy new net-zero electricity generation technologies that address reliability, decarbonization and affordability. The Energy Innovation team is focused on identifying projects that complement our hydro, wind and solar assets to deliver reliable and low-carbon electricity to customers. The Energy Innovation team is also looking at electrification more broadly to investigate potential new, adjacent business opportunities for TransAlta.

Our Energy Innovation team participates in the Low Carbon Peer Group, a discussion forum made up of TransAlta's peers in the electricity sector in the U.S. and Canada. We also continue to participate in the energy innovation ecosystem through engagement with various innovation accelerators that 'incubate' and accelerate start-ups by matching new technology solutions with practical problems identified by end-users, like TransAlta or our customers.

Renewable Energy

In 2024, TransAlta's nameplate capacity was 2,406 MW from wind and battery storage, 944 MW from hydro energy, and 181 MW from solar power. In 2024, our U.S. renewables fleet represented over 1 GW.

In April 2024, the Company achieved commercial operation of our 302 MW White Rock wind facilities, located in Oklahoma. The facilities are fully contracted to Amazon Energy LLC and currently supply clean and affordable electricity to our customer.

In May 2024, TransAlta achieved commercial operation of our 202 MW Horizon Hill wind facility, located in Oklahoma. The facility is fully contracted to Meta Platforms Inc., which is receiving both clean electricity and environmental attributes from the facility.

In 2023, the Garden Plain wind facility in Alberta was commissioned adding 130 MW to our gross installed capacity. The facility is fully contracted with Pembina Pipeline Corporation (100 MW) and PepsiCo Canada (30 MW). In addition, in 2023, the 48 MW Northern Goldfields solar and battery storage facilities in Western Australia achieved commercial operation.

Scaling Up Energy Solutions

Battery Storage

We continue to invest in battery energy storage systems as an important element to provide reliability through the energy transition – continuing an important role TransAlta has played for over 100 years with our hydro facilities.

In 2024, TransAlta's development pipeline included four energy storage projects in Canada: WaterCharger (project is on hold, lithium-ion battery storage, 180 MW), Tent Mountain (pumped hydro storage, 160 MW), Brazeau (pumped hydro storage, 300-900 MW) and New Brunswick Power Battery (battery, 10 MW). These projects could play various roles on electricity grids including providing reliability services and storing surplus generation for discharge at peak periods.

In 2023, the Northern Goldfields solar and battery storage facilities in Western Australia achieved commercial operation. The energy storage consists of the 10 MW/5 MWh Leinster Battery Energy Storage System which is integrated into TransAlta's remote network. The network and new generation supports BHP Nickel West to meet its emissions reduction targets and deliver lower-carbon nickel to its customers.

Electric Mobility

Companies can play an important role in reducing emissions by exploring the use of electric vehicles in their own operations. TransAlta is currently exploring the potential of electrifying our service fleet with zero-emission vehicles. In 2023, we launched a pilot project called Project Electrify to test four fully-electric vehicles at different facilities in Canada. The project will run from 2024 to 2025, during which time operators will gain hands-on experience with the technology and provide feedback on whether to pursue further electrification of our fleet.

Future Solutions

Hydrogen

In 2022, we announced a $2 million equity investment in Ekona's Series A funding round. The investment will help support the commercialization of Ekona's novel methane pyrolysis technology platform, which produces cleaner and lower-cost turquoise hydrogen. If successful, Ekona's distributed technology allows for on-site hydrogen

production, hence avoiding the need for costly transportation of hydrogen. Furthermore, its solid carbon byproduct allows for low-cost, low-emissions hydrogen production without the need for carbon sequestration. TransAlta is a member of Ekona's Strategic Committee and continues to work with Ekona as it develops its pyrolysis technology.

Small Modular Reactors (SMR)

Small modular reactors have a power capacity of up to 300 MW per unit and differ from traditional nuclear in that they modular, factory-assembled units transported to a location for installation. Additionally, they implement passive or walk-away safety features designed to dramatically reduce the risk of nuclear events. While high costs remain a challenge for all forms of nuclear, SMR developers argue that smaller MW plants made from manufactured components will allow the industry to access steep cost declines as the technology matures and more units are deployed. By providing reliable, emissions-free baseload power, nuclear power may play an important role in clean energy transitions.

In 2024, TransAlta announced a partnership with X-Energy Reactor Company, LLC to study the deployment of X-Energy's Xe-100 advanced small modular nuclear reactors in Alberta. With support from a grant from Emissions Reduction Alberta, the study will examine the feasibility of deploying X-Energy's advanced high-temperature gas-cooled small modular nuclear reactor at an existing coal-to-gas plant in Alberta.

TransAlta continues to monitor developments in SMR and explore the benefits of carbon dioxide removal options to support the net-zero transition of our operations, such as nature-based solutions, direct air capture, carbon capture, utilization and storage, and other technologies.

Hybrid Hydro Supercapacitor Energy Storage

In 2024, TransAlta launched a project with Atlas Power Technologies Inc. for a hybrid hydro supercapacitor energy storage system, which is expected to be the first of its kind in North America. With support from a grant from Emissions Reduction Alberta, the project is complementary to an existing hydroelectric generating station that augments the power plant's response time and capability to address frequency response needs.

Disruptive Technologies

In 2022, we entered into a commitment to invest US$25 million over the next four years in Energy Impact Partners' (EIP) Deep Decarbonization Frontier Fund 1 (the Frontier Fund) that invests in early-stage, innovative technology companies that seek to accelerate the transition to net-zero GHG emissions. TransAlta's investment in the Frontier Fund provides TransAlta with the opportunity to pool funds with some of the largest utilities in the U.S. and Europe to identify, pilot, commercialize and bring to market technologies that will support its decarbonization goals. In total, the Company invested US$12 million to this fund as at Dec. 31, 2024.

Fusion

Fusion technologies attempt to recreate the fusion reactions in the sun by fusing two hydrogen molecules together. If successful, fusion promises low-cost energy, with far shorter-lived nuclear waste.

Through EIP, TransAlta has invested in ZAP Energy, a leading fusion startup. ZAP Energy's technology stabilizes the hydrogen plasma using sheared flow (driving current through the flow creating the magnetic field confining and compressing the plasma) rather than magnetic fields. In 2022, ZAP announced it will conduct a feasibility study of retrofitting our retired Big Hanaford gas plant located in Centralia to host its first-of-a-kind Z-pinch fusion pilot plant. In 2024, ZAP received a second grant in the same amount of US$1 million from the Centralia Coal Transition Grants Energy Technology Board as part of energy transition investments to move away from coal in Washington State.

For more information on our investments in low-carbon research and development, refer to the Climate-Related Financial Metrics section of this MD&A.

Managing Environmental Resources

We continue to increase financial value from natural or environmental capital-related business activities, while striving to minimize our environmental footprint and potential risk factors related to environmental impacts. This section covers natural capital management partially in alignment with guidance from the IFRS's Integrated Reporting Framework.

Environmental Strategy

All energy sources used to generate electricity impact the environment. While we are pursuing a business strategy that includes investing in renewable energy resources such as wind, hydro and solar, we also believe that natural gas will continue to play an important role in meeting energy needs. In 2026, we expect that our generation mix will be made up of natural gas and renewable energy only.

Our Environmental Policy defines how we are integrating the protection of nature and the environment within TransAlta's strategy, our Total Safety Management System, as well as the principles of conduct for the management of natural resources.

Environmental Management System

At TransAlta, we operate our facilities in line with best practices related to environmental management standards. Our environmental management processes are verified annually to ensure we continuously improve our environmental performance. Our knowledge of environmental management systems (EMS) has matured since we aligned our processes in accordance with the internationally recognized ISO 14001 EMS standard. Currently, the most material natural or environmental capital impacts to our business are GHG emissions, air emissions (i.e., pollutants) and energy use. Other material impacts that we manage and track performance on via our environmental management practices include land use, water use, waste management and biodiversity.

In addition to our environmental management practices, we are subject to environmental laws and regulations that affect aspects of our operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of waste and hazardous substances. The Company's activities have the potential to damage natural habitat, impact vegetation and wildlife, or cause contamination to land or water that may require remediation under applicable laws and regulations. These laws and regulations require us to obtain and comply with a variety of environmental registrations, licences, permits and other approvals. The environmental regulations in the jurisdictions in which we operate are robust. Both public officials and private individuals may seek to enforce environmental laws and regulations against the Company. We interact with a number of regulators on an ongoing basis.

Nature-Related Risks and Opportunities

Nature-related risks may exist based on a Company's dependencies on and impacts to biodiversity, ecosystems and ecosystem services (BEES) and could result in nature-related events. These events could impact resource availability and sustainability, disrupt the supply chain necessary for successful operations, have negative regulatory compliance implications and cause reputational damage. Nature-related opportunities might exist when supporting or enhancing BEES, to the benefit of business operations. These opportunities can include accessing healthy, natural resources (i.e., soil and water), supporting a resilient ecosystem that is less prone to fluctuations (e.g., drought, flooding and erosion) and enhancing tourism and recreational opportunities.

Overseeing Nature-Related Issues

TransAlta's GSSC assists the Board in fulfilling its oversight responsibilities with respect to the Company's monitoring of environmental regulations, public policy changes and the development of strategies, policies and practices for the environment. For further information, refer to the Sustainability Governance section of this MD&A.

Assessing Nature-Related Dependencies and Impacts

In 2024, TransAlta conducted our first nature-related risks and opportunities assessment, achieving our 2022 sustainability target to "assess and disclose nature-related risks and opportunities including TransAlta's dependencies and impacts on ecosystems, land, water and air" by 2024.

We chose to follow the TNFD recommendations where possible, as a commitment to using internationally recognized methodologies. The analysis utilized the TNFD guidance on assessing nature-related issues—the Locate, Evaluate, Assess, Prepare (LEAP) approach—in conjunction with the TNFD Additional Sector Guidance – Electric Utilities and Power Generators (June 2024).

Methods applied include the review of environmental evaluations, permits and monitoring reports, the collection of environmental and geospatial data, the use of the TNFD data tools and the review of findings by internal and external subject matter experts. In addition, we adopted a TNFD scenario that projects moderate nature-related risks to business operations over the next 20 years, driven by gradual ecosystem degradation, climate change and shifting customer and shareholder expectations. This analysis excluded projections of physical risks related to climate change.

Given the large number of TransAlta's assets, a subset of facilities was selected and included over 3,100 MW of nameplate capacity from hydro, wind, solar, natural gas and coal facilities in Canada, the U.S. and Western Australia.

The following sections highlight TransAlta's top dependencies, impacts, risks, opportunities and mitigation measures related to nature.

Material Dependencies

We identified where and how the Company's operations may interface with nature and determined whether those interfaces are material. This means that our goal was not to understand or evaluate every potential issue, but rather focus on ecosystem services considered material to the operation of our selected facilities.

Our most material dependencies are associated with the regulation of the climate and climatic events, the use of water in production cycles, mainly in gas- and coal-fired power generation and the regulation of the water cycle, which enables the operation of hydroelectric facilities.

For further information on climate change, refer to the section Managing Climate Change Risks and Opportunities. of this MD&A.

TransAlta's nature-related dependencies found to be material are summarized in the table below.

Material Dependencies by Generation Type

Ecosystem service[1]	Hydro	Wind	Solar	Gas and coal
Groundwater	M	NA	VL	M
Surface water	VH	NA	VL	VH
Water supply	VH	VL	M	H
Water flow regulation	VH	NA	NA	M
Climate regulation[2]	VH	VH	VH	VL
Flood and storm protection	H	M	M	M
Soil stabilization and erosion control	H	M	M	L

Legend: (VL) Very Low, (L) Low, (M) Medium, (H) High, (VH) Very High and (NA) Not Applicable, as defined by the TNFD Additional Sector Guidance - Electric Uti ities and Power Generators (June 2024).

(1) The use of renewable resources (wind and solar radiation) and mineral resources (natural gas and coal), water flow regulation, flood and storm protection, and soil stabilization and erosion control are material to our operations but were excluded from this analysis because associated metrics were not available at an international scale. Faci ities have locally mandated controls to manage risks, including engineering solutions built into the design phase.

(2) Climate regulation services are the ecosystem contributions to the regulation of ambient atmospheric conditions and were excluded from this analysis because they are discussed in the section Managing Climate Change Risks and Opportunities.

Material Impact Drivers

Impact drivers are a measurable quantity of a natural resource that is used as an input to production (e.g., the volume of water consumed) or a measurable non-product output of a business activity (e.g., a kilogram of NOx emissions released into the atmosphere).

The analysis of TransAlta's material impact drivers included the assessment of 26 metrics related to land use, water, air emissions, GHG emissions, waste, species at risk, invasive alien species and enforcement actions or fines.

Our material nature-related impact drivers are associated with GHG emissions and the use of water as summarized in the table below.

Material Impact Drivers by Generation Type

Impact driver[1]	Hydro	Wind	Solar	Gas and coal
Land use change	VH	H	VH	NA
Freshwater use change	VH	M	NA	H
Water use	VH	NA	NA	VH
GHG emissions	L	NA	NA	VH
Non-GHG emissions	NA	NA	NA	VH
Water/soil pollutants	H	L	L	M
Solid waste	L	L	L	H
Area of land use	M	H	L	M
Area of freshwater use	H	NA	NA	M
Biological alterations[2]	H	NA	NA	NA

Legend: (L) Low, (M) Medium, (H) High, (VH) Very High and (NA) Not App icable, as defined by the TNFD Additional Sector Guidance - Electric Uti ities and Power Generators (June 2024).

(1) Noise and light disturbances are material to our operations but were excluded from this analysis because mitigations are built into project design and monitored during operations, in accordance with applicable regulatory requirements in the jurisdictions in which we operate. The state of nature (e.g., species extinction risk, direct morta ity, fisheries risk and incidents related to birds, bats, fish and others) is material to our operations but was not included in this table because the TNFD has not provided the associated materia ity ratings. Metrics related to the state of nature were included in our analysis and are summarized under the Biodiversity heading in the Environmental Performance section of this MD&A.

(2) Biological alterations or interferences include the impact from activities that directly introduce nonnative invasive species into areas of operation.

Potential Risks, Opportunities and Mitigation Measures

Nature-related risks are the potential threats posed to an organization linked to its dependencies on nature and its impacts on nature. These can derive from physical and transition risks.

The analysis of TransAlta's nature-related risks and opportunities was conducted with a focus on physical risks. These risks were evaluated to help us understand how our operations result in changes in the state of nature and how this affects ecosystem service provision.

Transition risks such as regulatory and policy, reputation, market and technology risks related to the Company are discussed in the Governance and Risk Management section of this MD&A. Transition risks related to climate change are disclosed in the Managing Climate Change Risks and Opportunities section of this MD&A.

Nature-related opportunities are activities that create positive outcomes for organizations and nature by avoiding or reducing impact on nature, or contributing to its restoration.

The metrics we use to assess and manage material nature-related dependencies and impacts as well as risks and opportunities in line with its strategy and risk management process can be found in the Environmental Performance section of this MD&A. Current and future nature-related targets can be found in the Our 2024 Sustainability Performance and 2025+ Sustainability Targets sections of this MD&A.

TransAlta's nature-related risks and opportunities and their mitigation measures are summarized in the following table.

Identified Potential Risks and Opportunities and Mitigation Measures

	Potential risks	Mitigation measures and opportunities
Hydro	Substantial alteration of natural water flow regimes is typical, leading to major changes in water levels, flow timing and velocity. Two facilities are located within 35 km of a World Heritage site as defined by the United Nations Educational, Scientific and Cultural Organization (UNESCO). These facilities are not within 35 km of Key Biodiversity Areas. Minimal impact related to land pollution, including spills, may occur. Facilities are located in areas with very low to low water stress, as determined by the Aqueduct Water Risk Atlas. Some facilities are located within critical habitat for species at risk. While there is potential for fish mortality, species extinction risk and mortality risk related to species listed by the International Union for Conservation of Nature (IUCN) are minimal. Typically, there is minimal impact from the emissions of GHG, SO_2, NO_x, particulate matter and mercury.	Most facilities maintain minimum or riparian flows to help support fish habitats despite the fluctuations in natural water flows. These measures aim to moderate the effects of dam operations on local water systems and wildlife. Our Cascade (36 MW) and Spray (112 MW) facilities are located within the Canadian Rocky Mountain Parks (UNESCO World Heritage Site). Cascade is located in and Spray is adjacent to Banff National Park. These facilities are Ecologo certified. This means that their energy products or services have undergone third-party testing for reduced impacts on aquatic, riparian and terrestrial ecosystems. In 2021, we renewed our previous agreement with the Government of Alberta for another five years to manage water flow on the Bow River at our Ghost Reservoir facility to aid in potential flood mitigation efforts, as well as at our Kananaskis River System (which includes the Interlakes, Pocaterra and Barrier hydroelectric plants) for drought mitigation efforts. In 2024, TransAlta signed onto a voluntary water-sharing memorandum of understanding with over 30 other water licence holders in the Bow River Basin in Alberta. Due to its role managing water storage and water flows in the Bow River system for power generation, drought prevention and flood control, the Company collaborates with other downstream water licence holders to manage water flows.
Wind	No measurable impact on water natural flow regimes. Facilities are located in areas with very low to moderate water stress. Some facilities are located within a Key Biodiversity Area, but not within 35 km of UNESCO World Heritage sites. Minimal impact related to land pollution, including spills, may occur. While there is potential for wildlife mortality, species extinction risk and mortality risk related to IUCN-listed species are minimal to low. Typically, there is minimal impact from the emissions associated with wind facilities.	Wind facilities can be associated with bird and bat mortalities. Given this, our wind facilities are required to complete post-construction mortality monitoring for a set number of years after the start of operations. If mortality exceeds acceptable levels, additional monitoring and mitigation measures are usually required (e.g., curtailment). Further information on mortality of species at risk can be found under the Biodiversity heading in the Environmental Performance section of this MD&A.
Solar	No measurable impact on water natural flow regimes. Facilities are located in areas with moderate water stress. Minimal impact related to land pollution, including spills, may occur. Some facilities are located within a Key Biodiversity Area, but not within 35 km of UNESCO World Heritage sites. While there is potential for wildlife mortality, species extinction risk is minimal. Mortality risk related to IUCN-listed species is moderate. Typically, there is minimal impact from the emissions associated with solar facilities.	Facilities are located in areas with moderate water stress. However, their water use is minimal. Typically, solar facilities can have high impacts on land use and land use change. These impacts could be reduced if facilities are small in size. This is the case with our North Carolina solar facility (122 MW), which is composed of 20 small sites throughout the state. Further information on mortality of species at risk can be found under the Biodiversity heading in the Environmental Performance section of this MD&A.

Identified Potential Risks and Opportunities and Mitigation Measures (Continued)

	Potential risks	Mitigation measures and opportunities
Natural gas	Some modification of water flow, affecting specific local stretches of water bodies is typical. Seasonal or operational impacts on flow may exist but are limited in scope and duration. Most facilities are located in areas with low water stress, but our Western Australian operations are located in areas with very high water stress. Facilities are not located within 35 km of Key Biodiversity Areas or UNESCO World Heritage sites. Minimal impact related to land pollution, including spills, may occur. Facilities are not located within critical habitat for species at risk. Species extinction risk and mortality risk related to IUCN-listed species are minimal to moderate. High to major impacts from the emissions of GHG, NO_x and particulate matter are typical, with minimal impact from SO_2 and mercury.	Water for gas operations is withdrawn primarily from rivers where we hold permits and must therefore adhere to regulations on the quality of discharged water. Our largest water withdrawal and discharge occurs at our Sarnia gas cogeneration facility (which produces both electricity and steam for our customers). The facility operates as a once-through, non-contact cooling system for our steam turbines. In 2024, we returned approximately 97 per cent of the water withdrawn from the adjacent St. Clair River to support our Sarnia operations. Our facilities in Western Australia have been designed to minimize water consumption. Water supply at these facilities is provided at no cost under PPAs with our mining customers, hence our risk is significantly mitigated. Water used in our operations is returned to our customers, who repurpose this water for vegetation and dust suppression in their mining operations. In addition, the South Hedland facility has developed a Water Efficiency Management Plan with Water Corporation WA, the principal supplier of water, wastewater and drainage services in Western Australia. Initiatives are aimed at reducing water consumption and costs through innovative technology and efficiencies identified through facility management. In 2022, we met our 2026 targets to achieve a 95 per cent reduction of SO_2 emissions and an 80 per cent reduction of NO_x emissions below 2005 levels and we retained the achievement over 2023 and 2024. We continue to progress towards our 2026 target to reduce scope 1 and 2 GHG emissions by 75 per cent from 2015 levels. Since 2015, we have reduced scope 1 and 2 GHG emissions by 22.7 MT CO_2e or 70 per cent.
Coal	TransAlta's sole remaining coal-fired generation facility, Centralia, is located in an area with very low water stress. Some modification of water flow, affecting specific local stretches of water bodies is typical. Seasonal or operational impacts on flow may exist but are limited in scope and duration. Centralia is not located within 35 km of Key Biodiversity Areas or UNESCO World Heritage sites. Minimal impact related to land pollution, including spills, may occur. Centralia is not located within critical habitat for species at risk. Species extinction risk and mortality risk related to IUCN-listed species are minimal. Typically, there is major impact from the emissions of GHG, SO_2, NO_x, particulate matter and mercury.	TransAlta historically operated three coal mines. The Whitewood mine in Alberta is completely reclaimed and the land was donated to the community. Further information can be found in the Case Study: TransAlta's Donation to the Alberta Conservation Association in the Community Investments section of this MD&A. The Highvale mine in Alberta closed in 2021 and the Centralia mine in Washington State closed in 2006. Both Highvale and Centralia are actively reducing their footprint through site reclamation, with targeted completion by 2046 and 2040 respectively. In 2021, we retired or converted all coal plants in Canada to natural-gas-fired generation. We plan to cease coal-fired generation at our Centralia plant in the U.S. by Dec. 31, 2025.

Environmental Performance

Our performance on managing environmental aspects is presented in the following sections and excludes the acquisition of Heartland Generation on Dec. 4, 2024.

Energy Use

TransAlta uses energy in a number of different ways. We burn natural gas, diesel and coal to generate electricity. We plan to cease coal-fired generation at Centralia by the end of 2025. We harness the kinetic energy of water and wind to generate electricity. We also generate electricity from the sun. In addition to combustion of fuel sources, we also track combustion of gasoline and diesel in our vehicles and the electricity use and fuel use for heating (such as natural gas) in the buildings we occupy. Knowledge of how much energy we use allows us to optimize and create energy efficiencies. As an electricity generator, we continually and consistently look for ways to optimize and create efficiencies related to the use of energy.

The following table captures our energy use (petajoules). Energy use decreased by 11 per cent in 2024 over 2023. Some values do not sum to the indicated total due to rounding. Zeros (0) indicate truncated values.

Year ended Dec. 31	2024	2023	2022
Hydro	**0**	0	0
Wind and Solar	**0**	0	0
Gas	**122**	123	130
Energy Transition	**52**	73	64
Corporate and Energy Marketing	**0**	0	0
Total energy use (petajoules)	**175**	197	195

Air Emissions

Our one remaining coal-fired facility emits air emissions that we track, analyze and report to regulatory bodies. We also work on mitigation solutions depending on the type of air emission. We report our major air emissions from coal, which include NO_x, SO_2, particulate matter and mercury. We continue reducing air emissions in our existing facilities through our conversion and retirement of coal units in Alberta (completed in 2021) and Washington State (planned completion by the end of 2025).

In 2022, we achieved our 2026 target of 95 per cent SO_2 and 80 per cent NO_x emissions reductions over 2005 levels. In 2025, TransAlta set a new target "By 2030, achieve a 90 per cent reduction of SO_2 emissions intensity from 2023 base year".

As per guidance from SASB, detailed air emissions disclosure is required when a facility is located within 49 kilometres of an area with a population greater than 50,000 persons.

Many of our gas facilities are located in very remote and unpopulated regions, away from dense urban areas. However, our Sarnia, Windsor, Ottawa, Fort Saskatchewan and Ada gas facilities and Centralia coal facility are located within 49 kilometres of dense or urban environments. In 2024, these facilities accounted for 41 per cent of total NO_x, 99 per cent of total SO_2, 31 per cent of total particulate matter and 56 per cent of total mercury.

Our total air emissions in 2024 show a decrease of 18 per cent for SO_2 and 18 per cent for NO_x from 2023 levels. This is primarily due to the decrease in production from our coal facility.

The following table represents our material air emissions. Figures have been rounded for SO_2 (to the nearest one hundred), NO_x (to the nearest one thousand), particulate matter (to the nearest ten, when possible) and mercury (to the nearest whole number).

Year ended Dec. 31	2024	2023	2022
SO_2 (tonnes)	**870**	1,100	1,200
NO_x (tonnes)	**8,700**	11,000	11,000
Particulate matter (tonnes)	**320**	460	360
Mercury (kilograms)	**16**	21	21

Water

Our principal water use is for cooling and steam generation in our coal and gas facilities, but our hydro operations also require water flow for operations. Water for coal and gas operations is withdrawn primarily from rivers where we hold permits and must therefore adhere to regulations on the quality of discharged water. The difference between withdrawal and discharge, representing consumption, is due to several factors, which include evaporation loss and steam production for customers, which we are unable to recover.

In 2022, we achieved our water consumption reduction target to reduce fleet-wide water consumption (withdrawals minus discharge) by 20 million m^3 or 40 per cent in 2026 over the 2015 baseline. Water consumption in 2015 was 45 million m^3. This target is in line with the UN SDGs, specifically "Goal 6: Clean Water and Sanitation." In 2024, we retained the achievement of this target. In 2025, TransAlta set a new target "By 2030, maintain water consumption intensity at 2023 levels".

In 2024, we withdrew approximately 237 million m^3 (2023 – 273 million m^3) and returned approximately 212 million m^3 (2023 – 239 million m^3) or 90 per cent. Overall, water consumption was approximately 25 million m^3 (2023 – 34 million m^3).

The following table represents our water withdrawal, water discharge and total water consumption (million m^3). Some values do not sum to the indicated total due to rounding. Figures below have been rounded to the nearest million m^3.

Year ended Dec. 31	2024	2023	2022
Water withdrawal	**237**	273	233
Water discharge	**212**	239	207
Total water consumption (million m^3)	**25**	34	26

Dam Safety

Our dam safety programs include all hydroelectric developments, constructed ponds and fluid retaining structures such as ash lagoons and canals, as well as associated equipment and structures and the personnel required to operate, maintain and inspect these items. They are governed through our Dam Safety Policy and Dam Safety Management System, which includes requirements on design, modification and decommissioning, operation, maintenance and surveillance, public safety, emergency management and risk management.

TransAlta's Board and its President and CEO oversee the effectiveness of our dam safety programs and receive regular updates. In 2022, a member of the Board was designated as the Company's Dam Safety Advisor to assist the Board in fulfilling its oversight role in regard to the Company's dam safety practices given the unique and technical aspects of dam safety. In addition, TransAlta engages an external Dam Safety Review Panel to provide external review of the program and its management, including overall assessment and benchmarking against other national and international programs. Our monitoring programs include:

- Regular operations and engineering inspections;
- Testing critical equipment;
- Numerous instruments in the dams monitoring water level, temperature, movement, earthquake detection;
- Use of drones and satellite remote movement monitoring;
- Emergency plans and exercises with internal and external stakeholders; and
- Regular third-party reviews that are shared with the regulators.

We work closely with local stakeholders including conservation authorities and public agencies on watershed management, emergency planning and flood response. In 2022, we started decommissioning the Keephills Ash

Lagoon, a facility that is no longer needed for ash storage following the coal-to-gas conversion of Keephills Unit 2. This project will reshape the existing lagoon so that it is stable for the long term and is the first step towards decommissioning the structure. Similar work is underway to remove the coal combustion waste storage ponds at the Centralia facility in Washington State.

TransAlta is proud of its reputation in dam safety. We participate in many industry associations including the Canadian Dam Association, Dam Safety Interest Group of the Centre for Energy Advancement through Technological Innovation, United States Society on Dams, Canadian Geotechnical Society, Dam Safety Advisory Committee of the Alberta Chamber of Resources and Association of State Dam Safety Officials.

For information on our corporate emergency management program, refer to Public Health and Safety in the Engaging with Our Stakeholders to Create Positive Relationships section of this MD&A.

Waste

The importance of environmental protection and waste management is outlined in our Environmental Policy as a corporate responsibility for TransAlta and its employees, and contractors working on TransAlta's behalf. Our waste data is reported annually to a number of different regulatory bodies.

In 2024, our operations generated approximately 384,000 tonnes equivalent of waste (2023 – 479,000 tonnes). Of the total waste generated, 98 per cent was non-hazardous waste and zero per cent was directed to landfill (2023 – 0.2 per cent). Since its retirement, we have been selling ash from our Highvale and Centralia Mine, which accounts for 97 per cent of the total waste generated.

The following table represents our total waste generation (tonnes equivalent). Figures have been rounded to the nearest one thousand.

Year ended Dec. 31	2024	2023	2022
Waste to landfill (tonne eq.)	**1,000**	1,000	2,000
Waste recycled (tonne eq.)	**12,000**	19,000	22,000
Waste reuse (tonne eq.)	**372,000**	457,000	453,000
Total waste generation (tonnes equivalent)	**384,000**	479,000	506,000
Percentage of total waste to landfill	**0.3**	0.2	0.4
Percentage of total waste: hazardous	**2.4**	3.5	5.0
Percentage of hazardous waste to landfill	**0.0**	0.0	0.0

Our reuse waste or byproduct waste is generally sold to third parties. Our operating teams are diligent at not only minimizing waste, but also maximizing recoverable value from waste. We have invested in equipment to capture byproducts from the combustion of coal, such as fly ash, bottom ash, gypsum and cenospheres, for subsequent sale. These non-hazardous materials add value to products like cement and asphalt, wallboard, paints and plastics.

Coal Ash Management

Given our transition off coal, we ceased producing fly ash waste in Canada at the end of 2021 and will no longer produce it past the end of 2025 in the U.S. In 2023, Lafarge Canada and TransAlta entered into an agreement designed to advance low-carbon concrete projects in Alberta. The project repurposes landfilled fly ash, a waste product from TransAlta's Highvale mine, which ceased operations in 2021. The ash is used to replace cement in concrete manufacturing. Turning the recovered product into something marketable, reduces the amount of cement produced and consequent emissions while offering new job and economic growth opportunities. This innovative technology contributes to reducing waste and is expected to reduce reclamation liabilities for TransAlta.

Land Use

Our largest land use had been associated with land disturbed by surface mining of coal, which we ceased to do in 2021. Of the three mines we operated, the Whitewood mine in Alberta is completely reclaimed and the land certification process is ongoing. Our Centralia mine in Washington State is currently in the reclamation phase and we have adopted a target to fully reclaim this mine by 2040.

Our Highvale mine in Alberta ceased operations on Dec. 31, 2021, when we discontinued coal-fired power generation in Canada. The mine reclamation of Highvale has been progressively executed as part of our regulatory approvals and our target is to have it fully reclaimed by 2046. In 2022, our reclamation team submitted our final reclamation plans. The updated plans align with community priorities

for the reclaimed land. In 2024, we continued contouring disturbed areas, re-establishing drainage, replacing topsoil and subsoil, and advancing re-vegetation and land management.

Our land use practices regarding previous mining activities incorporate progressive reclamation where the final end use of the land is considered at all stages of planning and development. To date, we have reclaimed approximately 5,000 hectares, which is equivalent to 40 per cent of land disturbed (12,500 hectares).

Biodiversity

The importance of environmental protection and biodiversity is outlined in our Environmental Policy as a corporate responsibility for TransAlta and a responsibility of each employee and contractor working on TransAlta's behalf. In 2022, the Company adopted the target to "achieve zero biodiversity-related incidents". This means zero biodiversity-related incidents that affected habitats and species included on the Red List of the IUCN from near threatened to critically endangered.

The following table represents our biodiversity incidents in accordance with the IUCN Red List classification.

Year ended Dec. 31	2024	2023	2022
Critically endangered	**0**	0	0
Endangered	**0**	0	0
Vulnerable	**0**	0	0
Near threatened	**0**	0	0
Total biodiversity-related incidents	**0**	0	0

Environmental Incidents and Spills

Protecting the environment supports healthy ecosystems and mitigates our environmental compliance risk and reputational risk. We maintain corporate incident management procedures, as part of our Total Safety Management System, for response, investigation and lessons learned to minimize environmental incidents. With respect to biodiversity management (management of ecosystems, natural habitats and life in the areas we operate), we seek to establish robust environmental research and data collection to establish scientifically sound baselines of the natural environment around our facilities to ensure we can accurately evaluate the level of significance to biodiversity following an incident.

We closely monitor the air, land, water and wildlife in these areas to identify and curtail potential impacts.

In 2024, no regulatory non-compliance environmental incidents were recorded (2023 – no incidents). No fines or environmental enforcement actions occurred.

The following table represents our regulatory non-compliance environmental incidents.

Year ended Dec. 31	2024	2023	2022
Regulatory non-compliance environmental incidents	**0**	0	1

Regarding spills and releases, efforts are placed on providing immediate response to all environmental spills to ensure assessment, containment and recovery of spilled materials result in minimal impact to the environment.

The volume of spills in 2024 was zero (0) m^3 (2023 – 0 m^3).

The following table represents our significant environmental incidents.

Year ended Dec. 31	2024	2023	2022
Significant environmental incidents	**0**	0	0

Engaging with Our Stakeholders to Create Positive Relationships

We strive to create shared value for our stakeholders through social and relationship value creation at TransAlta. The most material impacts on our social and relationship performance are fostering positive relationships with Indigenous neighbours, communities, stakeholders, governments, industry and landowners in the areas where we operate, as well as public health and safety. This section covers sustainability factors of social and relationship capital and intellectual capital partially in alignment with guidance from the IFRS's Integrated Reporting Framework. Performance outlined below excludes the acquisition of Heartland Generation on Dec. 4, 2024.

Inclusive Transition

In support of our energy transition, from 2012 to 2023, TransAlta invested US$55 million to support energy efficiency, economic and community development and education and retraining initiatives in Washington State. The investment is part of the TransAlta Energy Transition Bill passed in 2011. This bill was a historic agreement between policymakers, environmentalists, labour leaders and TransAlta to transition away from coal in Washington State by ceasing Centralia's coal-fired generation by the end of 2025.

Three funding boards were formed to invest the US$55 million starting in 2015: the Weatherization Board (US$10 million), the Economic and Community Development Board (US$20 million), and the Energy Technology Board (US$25 million). These boards are independent from TransAlta and provide grants to local businesses, non-profit organizations and local governments to improve energy efficiency, educate and retrain workers for the next generation of jobs and fund energy technology projects. To date, the Weatherization Board has invested US$10 million, the Economic and Community Development Board US$18.9 million and the Energy Technology Board US$15.5 million. Further information on Centralia Coal Transition Grants can be found on the website https://cctgrants.com/.

Additionally, in 2016, TransAlta announced that we had reached an agreement with the Government of Alberta for the cessation of emissions from coal-fired electricity generation facilities in Alberta (Off-Coal Agreement). As part of the Off-Coal Agreement, TransAlta has and continues to invest in programs and initiatives to support the communities surrounding the plants negatively impacted by the phase-out of coal generation during the transition.

Customers

TransAlta serves industrial and commercial customers with power and energy services across its fleet in Canada, the U.S. and Western Australia. We are focused on customer-centred growth to bring high levels of service quality and reliability for our customers. As one of the largest electricity generators in Canada, our team serves businesses with:

- Energy solutions starting from the design phase;
- Energy consumption and cost management solutions;
- Market price risk and volume exposure mitigation; and
- Monitoring of energy market design changes, price signals and applicable and available incentives.

The Customer Solutions team at TransAlta has maintained a large portfolio of customers in Alberta across a broad range of industry segments, including commercial real estate, municipal, manufacturing, industrial, hospitality, finance and oil and gas. Our work has been recognized by our customers through an average retention rate of 92 per cent over the last three years.

Across our business in Canada, the U.S. and Western Australia, we provide on-site generation for large mining and industrial customers. This requires us to continually engage with these customers, ensuring that current electricity requirements are provided safely, reliably and cost-effectively. We continue to explore opportunities to develop renewable energy facilities to support customers achieving their sustainability goals and targets, such as 100 per cent renewable power targets and/or GHG emissions reduction targets. Production from renewable electricity in 2024 resulted in the avoidance of approximately 2.8 million tonnes of CO_2e for our customers.

Our experience in developing and operating power facilities is highlighted below.

Power generation type	Operating experience (years)
Hydro	113
Natural Gas	74
Wind	27
Solar	10
Battery Energy Storage Systems	4

For further details on how we support our customers' sustainability objectives, please refer to the Enabling Innovation and Technology Adoption section of this MD&A.

Human Rights

TransAlta is committed to honouring domestic and internationally accepted labour standards and supports the protection of human rights of all its employees, contractors, suppliers, partners, Indigenous partners and other stakeholders. We abide by human rights and modern slavery legislation in Canada, the U.S. and Australia. We have a zero tolerance approach to discrimination based on age, disability, gender, race, religion, colour, national origin, political affiliation or veteran's status or any other prohibited ground as defined by human rights legislation in the jurisdictions in which we operate. We afford equal opportunities for all gender identities, support the right to freedom of association and the right to organize unions and bargain collectively. We do not conduct operational human rights reviews or impact assessments, but we have governance practices in place for the protection of human rights.

Our Human Rights and Discrimination Policy outlines our commitment to human rights in our operations and supply chain to ensure that our personnel policies and practices in our global operations respect fundamental rights. Expected behaviours of all our employees are set out in our Corporate Code of Conduct. We are committed to creating a work environment where all workers feel safe and are valued for the diversity they bring to our business. Our annual mandatory Code of Conduct training is required for employees prior to signing off the Code of Conduct. In 2024, 100 per cent of employees completed the training and acknowledged and signed the Code of Conduct. We also have adopted a Supplier Code of Conduct that defines the principles and standards expected of suppliers, their employees and contractors to meet while providing goods and/or services to TransAlta.

Our Whistleblower Policy provides a mechanism for our employees, officers, directors and contractors to report, among other things, any actual or suspected ethical or legal violations. We would seek to remedy the impact promptly in order to establish a corrective action plan in collaboration with the relevant individuals and stakeholders.

TransAlta files annual reports under Canada's *Fighting Against Forced Labour and Child Labour in Supply Chains Act* and Australia's *Modern Slavery Act 2018*. Such reports set forth the actions that we have taken to assess and address modern slavery risks within our operations and supply chain.

Supply Chain

We continue to seek solutions to advance supply chain sustainability. As we explore major projects, we assess vendors both at the evaluation stage and as part of information requests on such elements as safe work practices, environmental practices and Indigenous spend. This means, for example and for select procurement engagements, getting information on:

- Estimated value of services that will be procured though local Indigenous businesses;
- Estimated number of local Indigenous persons that will be employed;
- Understanding overall community spend and engagement; and
- Understanding the state of community relations through interview processes and stakeholder work.

In the coming years, we plan to develop ESG criteria for supply chain engagement and work to understand our direct suppliers' GHG emissions profile and targets. Our long-term plan is to collaborate with suppliers to explore enhancement of their GHG emissions targets and to consider setting direction for engaging suppliers with GHG emissions reduction targets.

In 2022, TransAlta approved a new goal to integrate sustainability into our supply chain. Our target is "By 2024, 80 per cent of our spend will be with suppliers that have a sustainability policy or commitment". This supports the intent of the UN SDG Target 12.7: "Promote public procurement practices that are sustainable, in accordance with national policies and priorities." In 2024, we confirmed that, on average, 79 per cent of our spend since 2022 was with suppliers that have a sustainability policy or commitment. Even though our target to achieve 80 per

cent of our spend with suppliers that have a sustainability policy or commitment by 2024 was not achieved, all vendors and suppliers of TransAlta are required to adhere to our Supplier Code of Conduct. Under this code, suppliers of goods and services to TransAlta are required to adhere to our core values, including health and safety, ethical business conduct and environmental leadership. The code also allows suppliers to report ethical or legal concerns via TransAlta's Ethics Helpline.

TransAlta will continue to consider other targets to help integrate sustainability into supply chain.

Indigenous Relationships and Partnerships

At TransAlta, we use our core values—safety, innovation, sustainability, respect and integrity—to guide our business practices and our engagement with stakeholders and Indigenous communities. We seek to build and nurture relationships and work to listen and understand the impacts our operations may have on local communities. We maintain open communication channels and are dedicated to resolving issues promptly and professionally through dialogue.

In addition to the Company's core values, engagement practices are guided by industry best practices and standards, corporate policies and regulatory requirements. Our commitment to Indigenous relations is spearheaded by a centralized corporate team that fosters a relationship-based approach, involving employees at our facilities and within each business unit.

TransAlta's Indigenous Relations Policy focuses on five key areas: awareness, community engagement, community investment, business development, employment and training. Efforts are focused on building and maintaining solid relationships and strong communication channels that enable TransAlta to: share information regarding operations and growth initiatives; gather feedback to inform project planning; and understand priorities and interests from communities to better address concerns and unlock opportunities.

Methods of engagement include:

- Relationship building through regular communication and meetings with representatives at various levels within Indigenous communities and organizations;
- Hosting company-community activities to share both business information and cultural knowledge;
- Maintaining consistent communications with each community and following appropriate community protocols and procedures;
- Participating in community events such as pow wows and blessing ceremonies; and
- Providing both monetary and in-kind sponsorships for community initiatives.

TransAlta strives to maintain relationships through the life cycle of our facilities, from project development and construction, through operation, until decommissioning phases are complete. This is recognized in our Indigenous Relations Policy, which includes acknowledgement and understanding of the intent of the recommendations of the United Nations Declaration on the Rights of Indigenous Peoples.

Support for Indigenous Youth, Education and Employment

TransAlta recognizes the importance of investing in Indigenous students and our financial support helps students complete their education, become self-sufficient and move forward to become future leaders in their communities.

In 2024, TransAlta provided more than $320,000 to support Indigenous youth, education and employment programs, representing 11 per cent of TransAlta's total community investment. Highlights include:

- The Read On Literacy Program (Read On) – In 2024, TransAlta partnered with Read On to provide elementary students in communities near our operations with in-person and virtual sessions. Read On is an Indigenous literacy program that seeks to mentor young people in First Nation schools to achieve their maximum academic, personal and social development by promoting the core values of education, literacy, taking pride in one's culture and making good decisions in one's life.
- In the Spirit of Planting Seeds – In 2024, TransAlta donated to the Growbox Project, an initiative by the Piikani Nation Lands Department aimed at addressing food security and promoting environmental stewardship. The project, titled "Sūpii ṗo'omaaksin" or "in the spirit of planting seeds," involves the development of a comprehensive greenhouse program that integrates renewable energy technologies and Blackfoot cultural teachings. The program includes a hydroponic farm for year-round food production, educational opportunities for students, and efforts to promote food sustainability and sovereignty within the Piikani Nation community.

Indigenous Cultural Awareness Training

In line with our sustainability target set in 2023, the Company made a deliberate effort to ensure that every new employee participated in Indigenous Cultural Awareness training. In 2024, TransAlta successfully reached 100 per cent completion of the Indigenous Cultural Awareness Training program during the onboarding of all new employees across our operating jurisdictions in Canada, the U.S. and Western Australia. This initiative has been instrumental in providing valuable insights into the rich history, culture and perspectives of Indigenous communities within the jurisdictions where we operate.

Case Study: Diamond Willow Youth Lodge

To meet the unique needs of Calgary's Indigenous youth, TransAlta has invested over $1 million since 2018 in the Diamond Willow Youth Lodge. Named after the species of willow tree used to build sacred sweat lodges, the diamond willow is known for its strength and flexibility making it ideal for creating the framework of the lodge.

This accessible and safe space provides a broad spectrum of support for the culture, identity, housing, mentorship and well-being needs of Indigenous youth aged 12 to 29. In 2023, 292 youth were supported by the lodge during 829 visits. The number of attendees has been increasing steadily year-over-year since inception. Over 165 events, workshops and activities were hosted including traditional cooking, drumming groups, hide and circle camps, tipi pole harvesting and tea ceremonies.

Stakeholder Relationships

Fostering positive relationships with our stakeholders is important to TransAlta. Driven by our core values, we see stakeholder transparency as an integral part of our business success. We work to build relationships and understand the importance of early and regular dialogue to determine what opportunities or impacts our activities may have on local stakeholders.

Our Stakeholders

To act in the best interests of the Company and optimize the balance between financial, environmental and social values of our stakeholders and TransAlta, we seek to:

- Build relationships through regular engagement with stakeholders regarding our operations, growth prospects and future developments;
- Consider feedback and make changes to project designs and plans to resolve and/or accommodate concerns expressed by our stakeholders; and
- Respond in a timely and professional manner to stakeholder inquiries and concerns and work diligently to resolve issues or complaints.

Our stakeholders are identified through stakeholder mapping exercises and prospective project development or acquisition. Through decades of establishing stakeholder relationships in the areas of our facilities, we have developed a strong knowledge of who our stakeholders are and have gained understanding of our stakeholders' issues and concerns. In many of our operating areas, we have decades of established relationships and work to maintain a consistent level of communication and trust. In newer areas, we spend time and effort on site listening and learning to ensure we consider all perspectives.

Our principal stakeholder groups are listed in the following table.

TransAlta Stakeholders

Non-governmental organizations	Community associations	Transmission facility operators
Regulators	Industry associations	Communities
Charitable organizations/Non-profit	Standards organizations	Retirees
All levels of government	Media	Residents/Landowners
Suppliers	Business partners	Investor organizations
Contractors	Unions/Labour organizations	Financial institutions
Government agencies	Resource industry associations	Mineral rights owners
System operators	Think tanks	Railroad owners
Customers	Academics	Utility owners
Shareholders	Employees	Creditors

Stakeholder Engagement

Our stakeholder engagement practices are guided by industry best practices, international standards, corporate policies and regulatory requirements. Examples of our methods of engagement are listed in the following table.

Information and communication	Dialogue and consultation	Relationship building
Open houses, town halls and public information sessions	In-person meetings with local groups and communities	Community advisory bodies
Newsletters, telephone conversations, emails and letters	Meetings with individual stakeholders (e.g., landowners and residents)	Capacity agreements
Websites	Targeted audience sessions	Sponsorships and donations
Social media postings	Tours of our facilities and sites	Hosting and attending events

A key focus of our work is to support business growth through proactive engagement with stakeholders in our geographic operating areas in Canada, the U.S. and Western Australia to develop and maintain relationships, assess needs and fit and seek out collaborative opportunities. This helps ensure any stakeholder concerns are identified and can be addressed early in the development process, thereby minimizing project delays. We conduct consultation during project development and construction phase and maintain engaged communication throughout operations to decommissioning phase.

In 2024, TransAlta was active in many communities in the jurisdictions where we operate. We delivered open houses, hosted community barbecues, conducted ongoing engagement with environmental, recreation and civil society groups and made numerous visits and interacted with non-profit organizations.

Community Investments

In 2024, TransAlta contributed approximately $2.9 million in donations and sponsorships (2023 – $3.2 million), with a continued focus in three priority areas: youth and education, environmental leadership and community health and wellness.

One of our significant community investments each year is to United Way campaigns. This year, TransAlta employees, retirees, contractors and the Company raised over $1.3 million for the United Way of Calgary and Area.

In 2024, TransAlta made a number of other significant investments, including the following highlights:

- Community Health and Wellness – In 2024, TransAlta donated to the Goldfields Women's Refuge Finlayson House in Australia, which offers a safe haven for women and children escaping domestic violence, providing them with shelter, support, and the tools to rebuild their lives.
- Environmental Leadership – In 2024, TransAlta donated to the Day on the Creek event as part of our commitment to supporting youth education and environmental stewardship in the Waterton Biosphere Region in Alberta. Our contribution helps provide valuable educational opportunities for students and the community, fostering a deeper understanding of watershed stewardship and the importance of preserving our natural environment.
- Youth and Education – In 2012, students from a kindergarten class were awarded a $2,500 college scholarship by TransAlta after winning a regional eco-challenge competition. In 2024, 19 students of the kindergarten class reached their high school graduation. As of their graduation date, the initial principal of the scholarship more than doubled. A celebration for the students and their families was held at the Centralia facility.

Case Study: TransAlta's Donation to the Alberta Conservation Association

In 2024, TransAlta and the Alberta Conservation Association (ACA) celebrated a significant milestone at the Whitewood Mine location. Through our partnership, TransAlta completed a donation of 1,274 acres to the ACA. This donation will ensure that the land remains preserved in its natural state, contributing to biodiversity and conservation efforts.

The Whitewood Mine, formerly a coal mine in Parkland County, Alberta required reclamation and conservation efforts to transform it into a sustainable natural habitat. The challenge was to preserve the land's diverse natural landscapes and ensure its long-term protection.

TransAlta's donation to the ACA is part of a larger effort to create the Whitewood Mine Conservation Site, which will encompass a total of 2,167 acres, combining past and present sales and donations. This makes it the largest continuous conservation property owned by the ACA in Alberta. The site features diverse natural landscapes, including a 100-acre lake, small water bodies and various natural habitats.

The transformation of the Whitewood Mine into a conservation area showcases the Company's commitment to environmental stewardship, reclamation and community engagement. Upon receiving its final reclamation

certificate, the ACA plans to open the site to the public, providing a valuable recreational and educational resource for the community.

Public Health and Safety

We are committed to protecting the public and our assets, as well as the physical, psychological and social well-being of our employees.

We specifically look to minimize the following risks:

- Harm to people;
- Damage to property;
- Operational liability; and
- Loss of organizational reputation and integrity.

We work to prevent incidents and lower our risk by administering security controls such as restricting physical access around and into our operating facilities. The use of security technology such as surveillance cameras and electronic access is utilized to ensure the control of secure areas. Regular audits and security risk assessments are conducted to ensure continuous improvement of the Security Management Program. Our Security Management Program is focused on the protection of people, property, information and reputation.

The Corporate Emergency Management Program prepares employees should an emergency incident occur. The program receives executive sponsorship and includes an emergency management policy and standard, which sets an expectation for employees to continuously prepare for emergencies. It provides an overarching framework for each business unit to provide an Emergency Response Plan and Business Continuity Plan. We implement our Incident Command System, which is a standardized on-scene emergency and incident management system that provides an organizational structure capable of responding to single or multiple incidents. Designed to aid in the management of resources during incidents, it combines facilities, equipment, personnel, procedures and communications operating within a common organizational structure. It is used as part of an all-hazards approach for incident management and is officially recognized for multi-agency response in emergency situations, however complex the incident might be.

We develop strong relationships with local emergency responders. We periodically conduct multi-agency training events at our facilities. This ensures continuous improvement and familiarity with our assets and builds strong communication channels for emergency response.

Our processes designate how we communicate with stakeholders in the event of a crisis. This is managed by our Crisis Communications Team. The team has the responsibility and goal to provide a unified message on behalf of the Company throughout the response and recovery, ensure all messaging is approved by the Incident Commander, co-ordinate messaging with any applicable external agencies and, if necessary, deploy them to an incident site.

Annual training, exercise and drill requirements are adhered to by our employees operating at our facilities. The results are tracked, audited and presented at our annual executive review. The findings and recommendations assist in maintaining an effective program across the organization.

Data and Digital Asset Protection

We work diligently to protect our digital assets, including our corporate data and our digital identities that provide access into line of business applications. Cybersecurity threats that compromise these assets include the manipulation of data integrity, system and network hacking, use of social engineering tactics through email phishing and compromise of operations and infrastructure through the use of ransomware, credential breaches and attacks introduced through unknowing third-party vendors and service providers.

Given the ever-evolving nature of cyberattacks, we are continuously adapting our cybersecurity program to focus on three key pillars: technology, processes and people. Each of these pillars can be reinforced independently to address specific cybersecurity risks and threats through a comprehensive and multi-faceted program. TransAlta continually assesses our cyber threat and risk levels through independent auditing and simulated cyber-attacks (i.e., penetration testing). Results from these assessments and exercises guide our cybersecurity strategy and practices, implementing measures and controls to proactively mitigate internal and external cybersecurity risks and threats posed to the organization.

TransAlta's Cybersecurity Policy defines how we identify and manage cybersecurity risks and threats, as well as how we detect, respond, and recover from cybersecurity incidents. We comply with all relevant legal, regulatory, industry standards and compliance requirements such as the North American Electric Reliability Corporation Critical Infrastructure Protection (NERC CIP), the Australian Security of Critical Infrastructure Act and the U.S. Sarbanes Oxley Act, where applicable. The NERC CIP and Australian Security of Critical Infrastructure rules are a set of standards aimed at regulating, enforcing, monitoring and managing the security of the North American and Australian power system. These compliance standards apply specifically to address cybersecurity risks.

In 2024, there were no identified cybersecurity breaches to our technology environment. Refer to Cybersecurity Risk in the Governance and Risk Management section of this MD&A for further details.

Building a Diverse and Inclusive Workforce

Engaging our workforce, developing our employees, creating an equitable, diverse and inclusive work environment and minimizing safety incidents are the keys to human capital value creation at TransAlta and our most material areas for management. In 2024, we enhanced our ESG performance through our efforts to promote an equitable, diverse and inclusive workforce. This section covers sustainability factors of human capital partially in alignment with guidance from the IFRS's Integrated Reporting Framework. Performance outlined below excludes the acquisition of Heartland Generation on Dec. 4, 2024.

Equity, Diversity and Inclusion

TransAlta's commitment and focus on excellence in equity, diversity and inclusion (ED&I) is found in our workplace and among our co-workers who advocate for the values of equity and inclusion at all working levels. This commitment is outlined in our Board and Workforce Diversity Policy and Diversity and Inclusion Pledge. We believe that a strong focus on ED&I will create a culture of belonging, allowing our employees to bring their authentic selves to work where they can thrive, innovate, improve service to our customers, deliver company results and positively impact the communities that we live in.

In 2024, TransAlta executed the fourth year of our five-year ED&I strategy to achieve the goals and aspirations defined in our ED&I Pledge.

Gender Diversity

A number of case studies have highlighted the link between gender diversity and additional business value. TransAlta is an active supporter of gender diversity as a driver for value, but also as an ethical business practice. Our commitment to gender diversity in our business is evidenced by our female participation rates on both our executive team and Board. In 2024, women made up 32 per cent of our executive team and 38 per cent of our Board.

To further support female advancement, we have set targets to: (i) maintain equal pay for women in equivalent roles, (ii) achieve 50 per cent representation of women on our Board by 2030 and (iii) achieve 40 per cent representation of women among all employees by 2030. Currently, women employees represent 28 per cent of all employees. Though the majority of our operational roles are currently held by male employees, we remain committed to achieving the 40 per cent goal in this time period.

In 2024, we continued with the Women in Trades Scholarship that provides eligible students enrolled in post-secondary trade programs with financial support. In 2024, we also continued with the gender diversity program in our Generation business to strategically target the recruitment of women. The program seeks to break down barriers and create opportunities for women to thrive in fields with historically lower female representation.

Workforce Health and Safety

At TransAlta, safety is a core value and is the foundation of how we operate. While generating affordable and reliable electricity for our customers is important, nothing is more important than the health and safety of our people and the communities we serve. We are committed to fostering a culture where we work and learn together to keep each other safe. Our focus on Operational Excellence puts into action our mission to safely do the right work at the right time to power and empower our communities.

Our management systems underpin the delivery of safe, reliable and competitive electricity to our customers and partners. The Company's Total Safety Management System is a combination of recognized best practices in process safety, risk management, asset management, occupational health, safety and environmental management.

At TransAlta, safety is a core part of everyone's role and a shared responsibility. As our safety culture maturity progresses, we are focused on cultivating a positive safety experience for everyone. We believe that the overall safety experience depends on the interaction between three elements: the physical work environment, the social environment and the individual environment. We made significant progress on our safety culture transformation journey through training and initiatives that support the three elements of positive safety. This training provides the tools and strategies to increase employees' ability to identify and control high energy hazards, enhance psychological safety and support mental health. At TransAlta, a positive safety culture is not only the absence of harm but the presence of protective factors that increase well-being.

In 2024, our strong safety performance was supported by our strategic areas of focus: maturing our safety culture, understanding risk and standardizing safety information and systems. To support our safety cultural growth, new employees and leaders completed training modules designed to gain tools to understand their role in setting, building, and maintaining our safety culture. Through peer board sessions designed to embed an understanding of human and organizational performance principles, serious injury and fatality prevention and psychological safety, leaders held over 100 sessions across the fleet.

One of our safety indicators is TRIF, which tracks the number of injury incidents that require treatment beyond first aid, relative to total exposure hours worked. Our TRIF

result for 2024 was 0.56 compared to 0.30 in 2023. We recorded zero serious injuries in 2024. The identification and control of high energy hazards is foundational to our strong performance on serious injury prevention.

The following table represents our corporate safety performance and includes employees and contractors.

Year ended Dec. 31	2024	2023	2022
Lost-time injuries	**0**	1	0
Medical aids	**6**	4	6
Restricted work injuries	**2**	0	0
Exposure hours	**2,844,000**	3,362,000	3,058,000
Total Recordable Injury Frequency (TRIF)	**0.56**	0.30	0.39

We focus on leading indicators and participation through Total Safety Reports (hazard, near miss, positive observations, and cybersecurity reports). Total Safety Report Frequency demonstrates the proactive activities, per worker per year, we are taking to identify and prevent an injury from occurring. We also report and recognize positive behaviours in the workplace to enhance psychological safety. This allows us to not only respond to incidents if they occur but find opportunities to strengthen barriers and layers of protection to mitigate potential incidents. In 2024, we recorded 16.3 reports per worker, which is above our exceptional performance target of 15. Evidence of the positive impacts associated with strong engagement and a maturing safety culture is apparent in TransAlta's overall safety performance. In 2024, TransAlta was recognized by the Alberta Mine Safety Association with the Trail Blazer Business Leader Award. This award recognizes executive leaders and senior managers for exemplary and inspiring leadership with a high commitment to health and safety.

Organizational Culture and Structure

Our employees are central to value creation. Our corporate culture has evolved and adapted throughout our 113-year history. Our values are safety, innovation, sustainability, respect and integrity. These five values help provide clarity for our employees and guide our behaviour and decision-making. They also provide a foundation for leadership, collaboration, community support, personal growth and work-life balance. Through corporate initiatives and support throughout all levels of leadership, we encourage our employees to maximize their potential.

Culture Transformation

In 2022, we embarked on our culture transformation journey with the goal of becoming a culture of results, purpose and learning. We developed a three-year culture strategy, Culture Charter and Culture Roadmap that defines milestones. For alignment and transparency, all of these documents are available to our employees. Part of our culture transformation involves improving employee psychological safety to encourage employees to speak up with a view to increase innovation, creativity and ultimately, results.

We conduct annual employee engagement surveys to gauge the employee experience, and based on survey results, leaders created action plans to drive improvement and increase engagement at the business unit and team level.

Finally, we are focused on improving employee health and well-being. To increase awareness, we have launched education sessions on a variety of topics such as mental health, women's health, men's health, nutrition, resiliency, etc.

Organizational Structure

In 2024, we had 1,205 (2023 – 1,257) active employees. With approximately 29 per cent of our employees being unionized, we strive to maintain open and positive relationships with union representatives and regularly meet to exchange information, listen to concerns and share ideas that further our mutual objectives. Collective bargaining is conducted in good faith and we respect the rights of employees to participate in collective bargaining.

Our organizational structure changed in 2024. Our business continues to operate four generating segments, with Gas, Wind and Solar, Hydro and Energy Transition, with support from our Corporate and Energy Marketing segments. Our operations portfolio is run by a single leadership team, which provides operational and financial synergies, thus enhancing our competitiveness.

Employee Retention and Recognition

ESG-Linked Compensation

At TransAlta, we have linked our ESG performance to our employees' compensation including that of our executive leadership team. Our annual and long-term incentive pay

for performance plans are linked to TransAlta achieving various sustainability goals, where the targets and metrics are reviewed and approved annually by our Board of Directors and further outlined in our annual compensation plans.

In 2024, 20 per cent of our annual incentive plan was linked to achieving specific ESG targets: 10 per cent referred to our organizational culture improvements and 10 per cent was linked to safety. Our long-term incentive plans include strategic goals related to leading in ESG policy development and progress towards our ESG targets. Refer to the Management Proxy Circular for additional details on our ESG related compensation.

Employee Performance and Recognition

Coaching, feedback and management are fundamental to our performance philosophy, with leaders and employees being asked to participate in regular meetings to discuss work progress, professional and career development throughout the year.

We strive to be an employer of choice through our HR and total rewards programs, which include pay-for performance incentive plans, as reviewed and approved by the Board of Directors. TransAlta's annual and long-term incentive plans are designed to measure and recognize employees' contributions towards metrics and targets. To motivate and engage employees in a timely manner, we continue to utilize employee recognition programs, including a quarterly recognition program and a peer-to-peer recognition program.

Talent Development

TransAlta places significant focus on talent development and retaining its employees. Annually, employees complete a combination of optional, mandatory and customized training as part of their roles. All employees have access to learning sessions from speakers who are experts on topics as varied as psychological safety, ED&I, mental and physical health, culture, financial wellness, core skills and leadership development.

Delivering Reliable and Affordable Energy

TransAlta's goal is to be a leading customer-centred electricity company, one that is committed to a sustainable future. Our strategy is focused on meeting our customers' need for affordable and reliable electricity, operational excellence and continual improvement. This section covers manufactured, intellectual and social and relationship capital management partially in alignment with guidance from the IFRS's Integrated Reporting Framework.

Energy Affordability

TransAlta helps commercial and industrial customers manage their cost of energy. TransAlta has a full suite of procurement strategies and products with various terms available to our customers to assist them in understanding and reducing their energy costs.

For customers interested in making a long-term commitment to obtain predictable costs, TransAlta has the experience to develop renewable energy facilities, battery energy storage systems and hybrid solutions, or long-term offtake agreements from its existing and future renewable and gas-fired facilities.

End-Use Efficiency and Demand

TransAlta's commercial and industrial customers have access to an extensive set of monthly reports providing detailed tracking of customer usage, allowing for corrective action as required, as well as cost-saving recommendations.

Our Power Factor Report advises customers if their sites are operating at less than a 90 per cent power factor so they can consider installing energy-efficient equipment. By reducing the customer's power system demand charge through power factor correction, the customer's site puts less strain on the electricity grid and reduces its carbon footprint. TransAlta's Site Health Report advises customers of a site whose peak demand has been permanently reduced for a variety of reasons from its initial in-service date. The customer may be paying a higher demand charge each month to the distribution company based on the original peak demand expected at the site. TransAlta collaborates with the customer and determines the new peak demand based on the customer's operation. The customer, working with the distribution company, may find it economic to buy down the distribution contract to reduce the monthly distribution costs going forward.

Grid Resiliency

As a large electricity generator, TransAlta works diligently to ensure the power we provide our customers is reliable and affordable. We provide decentralized and customized power solutions to industrial customers. We also supply power to centralized power systems and own and operate transmission grid infrastructure in Alberta that addresses system reliability needs.

In all jurisdictions where we operate, we work closely with the system operators to ensure overall supply adequacy and reliability of the grid. We consider a myriad of factors in our planning and operation decisions that could put grid resiliency at risk, including renewable energy intermittency, cyberattacks, extreme weather events and natural

disasters. We are also committed to ensuring strong compliance with North American Electric Reliability Corporation standards, Alberta Reliability Standards and the Power System Security and Reliability standards in the Western Electricity Market in Australia for the power plant and transmission infrastructure that we own and operate.

As a Company, we are keenly focused on deploying renewable and gas-fired power generation and new technology solutions to meet the emerging and future needs of the electric system that we operate in.

In 2020, WindCharger was the first battery energy storage asset ever developed in Alberta and was a leading participant in the Alberta Electric System Operator's pilot fast frequency response project. Fast frequency response is a novel and critical new fast-acting transmission reliability service that helps meet the needs of a more renewable-based grid by augmenting the electricity systems ability to recover from the sudden loss of generation or interties. WindCharger continues to provide of system reliability service.

In 2024, TransAlta launched a project with Atlas Power Technologies Inc. for a hybrid hydro supercapacitor energy storage system, which is expected to be the first of its kind in North America. With support from a grant from Emissions Reduction Alberta, the project is complementary to an existing hydroelectric generating station that augments the power plant's response time and capability to address frequency response needs.

For more information on technologies to support grid resiliency, refer to the Enabling Innovation and Technology Adoption section of this MD&A. For more information on extreme weather events and natural disasters, refer to Weather in the Managing Environmental Resources section of this MD&A.

Asset Management

TransAlta's asset management program is designed to deliver operational excellence by optimizing the total lifecycle value from physical assets across the Company's generation portfolio in Canada, the U.S. and Western Australia. The program involves a centralized team of engineers and specialists who collaborate with plant engineers and operators. They remotely monitor generation facilities for emerging equipment reliability and performance issues.

If an issue arises, the asset management engineer will assess and then notify facility operations of the findings to support investigation and remedy the issue to minimize the impact to operations. For example, if a wind turbine starts to show early signs of performance deviation compared to others, the operations team is notified and they will investigate and remedy the issue.

The monitoring, analysis and diagnostics completed by the asset management engineer enable early identification of equipment issues based on longer-term trend analysis and complements day-to-day facility operations. Anticipating risks and asset faults early allows for planned and scheduled repairs to be optimized and facility availability to be maximized.

Advanced Analytics

TransAlta has a dedicated data and analytics team that collaborates with the asset management and operations teams to leverage data science models, modernized technology platforms, and advanced analytics. Through this collaboration, solutions for specific use-cases are developed, enabling valuable insights that are actioned. Examples of these use-cases include data science models for detecting performance anomalies for wind turbines and models for detecting frequency excursions for compliance with the market rules.

Sustainability Governance

In order for an organization to truly integrate sustainability, it requires accountability at the Board and executive level. It requires an understanding of sustainability factors and associated corporate actions to address these issues, while continuing to balance operations and growth.

Sustainability is overseen by TransAlta's GSSC of the Board. The GSSC assists the Board in fulfilling its oversight responsibilities with respect to the Company's monitoring of climate change, environmental, health and safety regulations, public policy changes and the development of strategies, policies and practices for climate change, environment, health and safety and social well-being, including human rights, working conditions and responsible sourcing.

The following policies help govern sustainability at TransAlta and are publicly available in the Governance section of the Investor Centre on our website:

- Corporate Code of Conduct
- Supplier Code of Conduct
- Whistleblower Policy
- Total Safety Management Policy
- Human Rights and Discrimination Policy
- Indigenous Relations Policy
- Board and Workforce Diversity Policy and Diversity and Inclusion Pledge
- Environmental Policy

In 2024, our sustainability memberships included key sustainability organizations and working groups such as the IFRS Sustainability Alliance, the Trellis Network (formerly GreenBiz) and the Electricity Canada Sustainable Electricity Steering Committee and Climate Change Adaptation Committee, which all provide validation and support of our sustainability strategy and practices.

In 2024, our material sustainability factors remained unchanged from 2022. They are presented below in alphabetical order.

- Air quality and emissions
- Asset integrity and grid resiliency
- Biodiversity and land management
- Climate change and greenhouse gas emissions
- Dam safety
- Energy use and conservation
- Equity, diversity and inclusion
- Ethics and business conduct
- Health, safety and well-being
- Human rights and labour practices
- Indigenous relationships and partnerships
- Information asset protection and cybersecurity
- Renewable energy and innovative technologies
- Security and emergency preparedness and response
- Stakeholder engagement and community investment
- Supply chain and sustainable sourcing
- Sustainability governance
- Sustainable finance
- Talent attraction, retention and development
- Waste management
- Water management

For additional details on governance, refer to the Governance and Risk Management section of this MD&A.

Governance and Risk Management

Our business activities expose us to a variety of risks and opportunities including, but not limited to, regulatory changes, rapidly changing market dynamics and increased volatility in our key commodity markets. Our goal is to manage these risks and opportunities so that we are in a position to develop our business and achieve our goals while remaining reasonably protected from an unacceptable level of risk or financial exposure. We use a multi-level risk management oversight structure to manage the risks and opportunities arising from our business activities, the markets in which we operate and the political environments and structures with which we interact.

Governance

The key elements of our governance practices are:

- Employees, management and the Board are committed to ethical business conduct, integrity and honesty;
- We have established key policies and standards to provide a framework for how we conduct our business;
- The Chair of our Board and all directors, other than our President and CEO, are independent within the meaning of National Instrument 58-101 — Disclosure of Corporate Governance Practices;
- The Board includes individuals with a mix of skills, knowledge and experience that are critical for our business and our strategy;
- The effectiveness of the Board is achieved through robust annual evaluations and continuing education of our directors; and
- Our management and the Board facilitate and foster an open dialogue with shareholders and community stakeholders.

Commitment to ethical conduct is the foundation of our corporate governance model. We have adopted the following codes of conduct to guide our business decisions and everyday business activities:

- Corporate Code of Conduct, which applies to all employees and officers of TransAlta and its subsidiaries;
- Directors' Code of Conduct;
- Supplier's Code of Conduct;
- Finance Code of Ethics, which applies to all financial employees of the Company; and
- Energy Trading Code of Conduct, which applies to all of our employees engaged in energy marketing.

Our Corporate Code of Conduct outlines the standards and expectations we have for our employees, officers, directors, consultants and suppliers with respect to, among other things, the protection and proper use of our assets. The codes also provide guidelines with respect to securing our assets, avoiding conflicts of interest, respect in the workplace, social responsibility, privacy, compliance with laws, insider trading, environment, health and safety and our commitment to ethical and honest conduct. Our Corporate Code of Conduct and Directors' Code of Conduct each goes beyond the laws, rules and regulations that govern our business in the jurisdictions in which we operate; they outline the principal business practices with which all employees and directors must comply.

Our employees, officers and directors are informed annually about the importance of ethics and professionalism in their daily work and must certify annually that they have reviewed and understand their responsibilities as set forth in the respective codes of conduct. This certification also requires our employees, officers and directors to acknowledge that they have complied with the standards set out in the respective code during the last calendar year.

The Board provides stewardship of the Company and ensures that the Company establishes key policies and procedures for the identification, assessment and management of principal risks and strategic plans. The Board monitors and assesses the performance and progress of the Company's goals through candid and timely reports from the CEO and the senior management team. We have also established an annual evaluation process whereby our directors are provided with an opportunity to evaluate the Board, Board committees, individual directors and the Chair of the Board's performance.

To allow the Board to establish and manage the financial, environmental and social elements of our governance practices, the Board has delegated certain responsibilities to the AFRC, GSSC, the Human Resources Committee (the HRC) and the Investment Performance Committee (IPC).

The AFRC, consisting of independent members of the Board, provides assistance to the Board in fulfilling its oversight responsibility relating to the integrity of our consolidated financial statements and the financial reporting process; the systems of internal accounting and financial controls; the internal audit function; the external auditors' qualifications and terms and conditions of appointment, including remuneration, independence, performance and reports; and the legal and risk compliance programs as established by management and the Board. The AFRC approves our Commodity and Financial Exposure Management policies and reviews quarterly ERM reporting.

The GSSC is responsible for developing and recommending to the Board a set of corporate governance

principles applicable to the Company and for monitoring compliance with these principles. The GSSC is also responsible for Board recruitment, succession planning and for the nomination of directors to the Board and its committees. In addition, the GSSC assists the Board in fulfilling its oversight responsibilities with respect to the Company's monitoring of climate change, environmental, health and safety regulations, public policy changes and the development of strategies, policies and practices for climate change, environmental, health and safety and social well-being, including human rights, working conditions and responsible sourcing. The GSSC also receives an annual report on the annual codes of conduct certification process. For further information on the Board's oversight of climate-related factors, refer to Climate Change Governance in the ESG section of this MD&A.

In regards to overseeing and seeking to ensure that the Company consistently achieves strong environment, health and safety (EH&S) performance, the GSSC undertakes a number of actions that include: (i) receiving regular reports from management regarding environmental compliance, trends and TransAlta's responses; (ii) receiving reports and briefings on management's initiatives with respect to changes in climate change legislation, policy developments as well as other draft initiatives and the potential impact such initiatives may have on our operations; (iii) assessing the impact of the GHG policies implementation and other legislative initiatives on the Company's business; (iv) reviewing with management the EH&S policies of the Company; (v) reviewing with management the health and safety practices implemented within the Company, as well as the evaluation and training processes put in place to address problem areas; (vi) discussing with management ways to improve the EH&S processes and practices; (vii) considering and recommending our sustainability targets to the Board and evaluating our performance against such targets; (viii) reviewing the effectiveness of our response to EH&S issues and any new initiatives put in place to further improve the Company's EH&S culture; and (IX) reviewing our safety performance.

The HRC is empowered by the Board to review and approve the Company's key compensation and human resources policies that are intended to attract, recruit, retain and motivate employees. The HRC also makes recommendations to the Board regarding the compensation of the CEO, including the review and adoption of equity-based incentive compensation plans, the adoption of human resources policies that support human rights and ethical conduct and the review and approval of executive management succession and development plans.

The IPC is empowered by the Board to oversee management's investment conclusions and the execution of major Board-approved capital expenditure projects that further the Company's strategic plans. The IPC helps the Board in fulfilling its oversight responsibilities with respect to broadly reviewing and monitoring project management and control processes, financial profile, capital costs, procurement practices and project schedules in a more in-depth manner than time permits during regularly scheduled Board meetings.

The responsibilities of other stakeholders within our risk management oversight structure are described below:

The CEO and executive management review and report on key risks quarterly. Specific Trading Risk Management reviews are held monthly by the Commodity Risk and Compliance Committee and weekly by the commodity risk team, the commercial managers in Trading and Marketing and the Executive Vice-President, Finance and Chief Financial Officer.

The Investment Committee is a management committee chaired by our Executive Vice-President, Finance and Chief Financial Officer and comprises the President and Chief Executive Officer; Executive Vice-President, Generation; Executive Vice-President, Commercial and Customer Relations; and Vice-President, Corporate Strategy. It reviews and approves all major capital expenditures including growth, productivity, life extensions and major coal outages. Projects that are approved by the Investment Committee will then be put forward for approval by the Board, if required.

The Commodity Risk & Compliance Committee is chaired by our Executive Vice-President, Finance and Chief Financial Officer and comprises at least three members of senior management. It oversees the risk and compliance program in trading and ensures that this program is adequately resourced to monitor trading operations from a risk and compliance perspective. It also ensures the existence of appropriate controls, processes, systems and procedures to monitor adherence to policy.

The Hydro Operating Committee consists of two members who are Brookfield employees with expertise in hydro facility management and two TransAlta members. This committee was formed in 2019 to collaborate on matters in connection with the operation and maximization of the value of TransAlta's Alberta Hydro Assets. It is delivering on its objectives by reviewing the operating, maintenance, safety and environmental aspects of TransAlta's Alberta Hydro Assets and, following that review, providing advice and recommendations to TransAlta's hydro operational team. The Hydro Operating Committee has an initial term of six years, which can be extended for an additional two years.

TransAlta is listed on the Toronto Stock Exchange and the New York Stock Exchange and is subject to the governance regulations, rules and standards applicable under both exchanges. Our corporate governance practices meet the following governance rules and guidelines of the TSX and Canadian Securities

Administrators: (i) Multilateral Instrument 52-109 — Certification of Disclosure in Issuers' Annual and Interim Filings; (ii) National Instrument 52-110 — Audit Committees; (iii) National Policy 58-201 — Corporate Governance Guidelines; and (iv) National Instrument 58-101 — Disclosure of Corporate Governance Practices. As a "foreign private issuer" under U.S. securities laws, we are generally permitted to comply with Canadian corporate governance requirements. Additional information regarding our governance practices can be found in our most recent management information circular.

Risk Controls

Our risk controls have several key components:

Enterprise Tone

We strive to foster beliefs and actions that are true to and respectful of our many stakeholders. We do this by investing in communities where we live and work, operating and growing sustainably, putting safety first and being responsible to the many groups and individuals with whom we work.

Policies

We maintain a comprehensive set of enterprise-wide policies. These policies establish delegated authorities and limits for business transactions, and they allow for an exception approval process. Periodic reviews and audits are performed to ensure compliance with these policies. All employees and directors are required to sign the Corporate Code of Conduct on an annual basis.

Reporting

On a regular basis, residual risk exposures are reported to key decision-makers including the Board, the AFRC, senior management and/or the Commodity Risk & Compliance Committee, as applicable. Reporting to this latter committee includes analysis of new risks, monitoring of status to risk limits, the review of events that can affect these risks and discussion and the review of the status of actions to minimize risks. This monthly reporting provides for effective and timely risk management and oversight.

Whistleblower System

We have a process in place where employees, contractors, shareholders or other stakeholders may confidentially or anonymously report any potential legal or ethical concerns, including concerns relating to accounting, internal control accounting, auditing or financial matters or relating to alleged violations of any laws or our Corporate Code of Conduct. These concerns can be submitted confidentially and anonymously, either directly to the AFRC or through TransAlta's toll-free telephone or online Ethics Helpline. The AFRC Chair is immediately notified of any material complaints and, otherwise, the AFRC receives a report at every quarterly committee meeting on all findings related to any material complaints or complaints relating to accounting or financial reporting or alleged breaches in internal controls over financial reporting.

Value at Risk and Trading Positions

Value at risk (VaR) is one of the primary measures used to manage our exposure to market risk resulting from commodity risk management activities. VaR is calculated and reported on a daily basis. This metric describes the potential change in the value of our trading portfolio over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations.

VaR is a commonly used metric that is employed by industry to track the risk in commodity risk management positions and portfolios. Two common methodologies for estimating VaR are the historical variance/covariance and scenario analysis approaches. We estimate VaR using the historical variance/covariance approach. An inherent limitation of historical variance/covariance VaR is that historical information used in the estimate may not be indicative of future market risk. Stress tests are performed periodically to measure the financial impact to the trading portfolio resulting from potential market events, including fluctuations in market prices, volatilities of those prices and the relationships between those prices. We also employ additional risk mitigation measures. VaR at Dec. 31, 2024, associated with our proprietary commodity risk management activities was $3 million (2023 – $4 million). Refer to the Risk Factors – Commodity Price Risk section of this MD&A below for further discussion.

Risk Factors

Risk is an inherent factor of doing business. The following section addresses some, but not all, risk factors that could affect our future plans, performance, results or outcomes and our activities in mitigating those risks. These risks do not occur in isolation, but must be considered in conjunction with each other.

A reference herein to a material adverse effect on the Company means such an effect on the Company or its business, operations, financial condition, results of operations and/or its cash flows, as the context requires.

For some risk factors, we show the after-tax effect on net earnings (loss) of changes in certain key variables. The analysis is based on business conditions and production volumes in 2024. Each item in the sensitivity analysis assumes all other potential variables are held constant. While these sensitivities are applicable to the period and the magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or for a greater magnitude of changes. The changes in rates should also not be assumed to be proportionate to earnings in all instances.

Equipment failure and the operation and maintenance of our facilities involve risks that may materially and adversely affect our business.

There is a risk of equipment failure or underperformance to our operations due to wear and tear, latent defect, design error or operator error, among other things, which could have a material adverse effect on our business. Although our generation facilities have generally operated in accordance with expectations, there can be no assurance that they will continue to do so. Our facilities are exposed to operational risks that can lead to outages and increased production risk which could have a material adverse effect on our business. Further, some of our generation facilities were constructed many years ago and may require significant capital expenditures to maintain peak reliability or operations. Newer facilities also require various levels of capital expenditures to maintain peak reliability or operations. There can be no assurance that our maintenance program will be able to detect potential failures in our facilities before they occur or eliminate all adverse consequences in the event of failure.

As well, we are exposed to procurement risk for specialized parts that may have long lead times. If we are unable to procure these parts when they are needed for maintenance activities, we could face an extended period where our equipment is unavailable to produce electricity. Further, if a manufacturer is unable or unwilling to provide satisfactory maintenance or warranty support on reasonable terms, we may have to enter into alternative arrangements with other providers or perform the services ourselves. These arrangements could be more expensive to us than our current arrangements and if we are unable to enter into satisfactory alternative arrangements, our inability to access technical expertise or parts could have a material adverse effect on us. TransAlta manages this risk with our capital spares policy.

While we maintain an inventory of, or otherwise make arrangements to obtain, spare parts to replace critical equipment and maintain insurance for property damage and business interruption to protect against certain operating risks, these protections may not be adequate to cover lost revenues or increased expenses and penalties that could result if we were unable to operate our generation facilities at a level necessary to comply with our contracts. In addition, circumstances could arise in the future whereby the Company may be obligated to produce power at a cost that exceeds the revenues being derived therefrom.

There can be no assurance that any applicable insurance coverage would be adequate to protect our business from material adverse effects. In addition, there can be no assurance that we will be able to restore equipment or assets that have reached the end of their useful lives.

We manage our generation equipment and technology risk by:

- Operating our facilities within defined industry standards that optimize availability over their commercial operating life;
- Performing preventive maintenance in accordance with applicable industry practices, major equipment supplier recommendations and our operating experience;
- Adhering to comprehensive maintenance programs and regular turnaround schedules;
- Adjusting maintenance plans by facility to reflect equipment type, age and commercial risk;
- Having adequate business interruption insurance in place to cover extended forced outages;
- Having clauses in our PPAs and other long-term contracts that allow us to declare force majeure in the event of an unforeseen failure;
- Selecting and applying proven technology in our generating facilities, where practical;
- Where technology is newer, ensuring service agreements with equipment suppliers include appropriate availability and performance guarantees;
- Monitoring our fleet against industry performance to identify issues or advancements that may impact performance and adjusting our maintenance and investment programs accordingly;
- Negotiating strategic supply agreements with selected vendors to ensure key components are readily available in the event of a significant outage;
- Monitoring the condition of our assets and performing predictive analytics, and adjusting our maintenance programs to maintain availability;
- Entering into long-term arrangements with our strategic supply partners to ensure availability of critical spare parts; and
- Implementing long-term asset management strategies that optimize the life cycles of our existing facilities and/or identify replacement requirements for generating assets.

Unexpected changes in the cost of maintenance or in the cost and durability of components for the Company's facilities may adversely affect the results of our operations.

Inflation or other increases in the Company's cost structure that are beyond the control of the Company could materially adversely impact our financial performance. Examples of such costs include, but are not limited to, unexpected increases in the cost of procuring materials

and services required for maintenance activities, and unexpected replacement or repair costs associated with equipment underperformance or lower-than-anticipated durability.

Changes in the price of electricity may materially adversely affect our business.

A portion of our revenues are tied, either directly or indirectly, to the market price for electricity in the markets in which we operate, and in particular in the Alberta electricity market. Market electricity prices are impacted by a number of factors, including the strength of the economy, the available transmission capacity, the price of fuel that is used to generate electricity (and, accordingly, certain of the factors that affect the price of fuel described below), the management of generation, the amount of excess generating capacity relative to load in a particular market, the cost of controlling emissions and cost of carbon, the structure of the particular market, the availability of transmission (including from other jurisdictions), increased adoption of energy-efficiency and conservation initiatives, and weather conditions that impact electrical load. As a result, we cannot precisely predict future electricity prices and electricity price volatility (particularly lower Alberta electricity prices) that could have a material and adverse effect on us. Further, the Alberta market is the only fully deregulated electricity market in Canada and this market structure permits corporate offtakers to invest in new renewable generation in the province solely for ESG reasons (i.e., to align with decarbonization goals) that may not align with supply and demand fundamentals. This could potentially result in an oversupply of intermittent electricity in the Alberta electricity market and could put downward pressure on electricity prices and contribute to significant price volatility in the near term.

Our facilities and construction projects have structured agreements in their contracts around force majeure events that are beyond our control, but positions the organization to industry standards for insurance or contract claw back in costs. Such events could result in material adverse effects.

Our facilities, construction projects and operations are exposed to potential interruption and damage, or partial or full loss resulting from environmental disasters (e.g., floods, high winds, fires, ice storms, earthquakes and public health crises, such as pandemics and epidemics), other seismic activity and equipment failures. Climate change can also increase the frequency and severity of these extreme weather events. There can be no assurance that in the event of an earthquake, flood, cyclone, hurricane, tornado, tsunami, terrorist attack, act of war or other natural, man-made or technical catastrophe, all or some parts of our generation facilities and infrastructure systems will not be disrupted. The occurrence of a significant event that disrupts the ability of our power generation assets to produce power for an extended period, including events that preclude existing customers under PPAs from purchasing electricity, could have a material negative impact on our business. Our facilities, construction projects and operations could be exposed to the effects of severe weather conditions, natural and man-made disasters and other potentially catastrophic events. The occurrence of such an event may not release us from performing our obligations pursuant to PPAs or other agreements with third parties. In addition, many of our generation facilities are located in remote areas, which can make repair of damage costly or difficult to access. Catastrophic events, including public health crises, could result in volatility and disruption to global supply chains, disruption to global financial markets, trade and market sentiment, risks to employee health and safety, a slowdown or temporary suspension of operations in impacted locations, postponements in the initiation and/or completion of the Company's development or construction projects, and delays in the completion of services, any of which may result in the Company incurring penalties under contracts, additional costs or the cancellation of contracts.

Risks relating to TransAlta's development and growth projects and acquisitions may materially and adversely affect us.

Development and growth projects and acquisitions that we undertake may be subject to execution and capital cost risks, including, but not limited to, risks relating to regulatory approvals, third-party opposition, cost escalations, securing land rights, construction delays, shortages of raw materials, supply chain constraints, or skilled labour and capital constraints. The occurrences of these risks could have a material and adverse impact on us, our financial condition, our ability to operate and our cash flows.

Expansion of our business through development projects and acquisitions may place increased demands on our management, operating systems, internal controls and financial and physical resources. In addition, the process of integrating acquired businesses or development projects may involve unforeseen difficulties. Failure to successfully manage or integrate any acquired businesses or development projects could have a material adverse impact on us, our financial condition, our ability to operate and our cash flows. Further, we cannot make assurances that we will be successful in integrating any acquisition or that the commercial opportunities or operational synergies of any acquisition will be realized as expected.

We may pursue acquisitions in new markets that are subject to regulation by various foreign governments and regulatory authorities and to the application of foreign laws. Such foreign laws or regulations may not provide for the same type of legal certainty and rights, in connection with our contractual relationships in such countries, as are

afforded to us currently, which may adversely affect our ability to receive revenues or enforce our rights in connection with any such foreign operations. In addition, the laws and regulations of some countries may limit our ability to hold a majority interest in some of the projects that we may acquire, thus limiting our ability to control the operation of such projects. Any existing or new operations may also be subject to significant political, economic and financial risks, which vary by country, and may include: (a) changes in government policies or personnel; (b) changes in general economic conditions; (c) restrictions on currency transfer or convertibility; (d) changes in labour relations; (e) political instability and civil unrest; (f) regulatory or other changes in the local electricity market; and (g) breach or repudiation of important contractual undertakings by governmental entities and expropriation and confiscation of assets and facilities for less than fair market value.

With respect to acquisitions, we cannot make assurances that we will identify suitable transactions or that we will have access to sufficient resources, through our credit facilities, the capital markets or otherwise, to pursue and complete any identified acquisition opportunities on a timely basis and at a reasonable cost. Any acquisition that we propose or complete would be subject to regulatory approvals and other normal commercial risks that could result in the transaction not being completed on the terms anticipated, on time, or at all. In the event we are unable to close a transaction that we've entered into, we may be subject to termination fees that could become payable to the vendor. An unavoidable level of risk remains regarding potential undisclosed or unknown liabilities relating to any acquisition. The existence of such undisclosed liabilities may have a material adverse impact on our business, financial condition, results of operations and cash flows.

There can be no assurance that the Company will realize the anticipated benefits in respect of the Heartland Generation acquisition.

The acquisition of Heartland Generation may not deliver the anticipated benefits expected to arise from such transaction, including as it pertains to accretion to free cash flow, the remaining life of the Heartland Generation assets and the ability for such assets to generate sufficient average annual EBITDA to meet the Company's expectations. Furthermore, as with all development projects, there are risks related to the development of the 400 MW Battle River Carbon Hub Project held by Heartland Generation, including risk relating to the project's continued development, the ability to obtain regulatory approval and the economic outlook required to support a final investment decision.

We could suffer lost revenues or increased expenses and penalties if we are unable to operate our generation facilities at a level necessary to comply with our PPAs.

The ability of our facilities to generate the maximum amount of power or steam that can be sold under PPAs is an important determinant of our revenues. Under certain PPAs, if the facility is not capable of generating electricity or steam for the required availability in a given contract year, penalty payments may be payable to the relevant purchaser by us and could give rise to termination rights. The payment of any such penalties or the termination of such PPAs could adversely affect our revenues and profitability.

We are dependent on access to parts and equipment from certain key suppliers and we may be adversely affected if these relationships are not maintained.

Our ability to compete and expand depends on having access, at a reasonable cost, to equipment, parts and components that are technologically and economically competitive with those used by our competitors. Although we have individual framework agreements with various suppliers, there can be no assurance that these relationships with suppliers will be maintained or not adversely affected. If they are not maintained, or are adversely affected, our ability to compete may be impaired due to lack of access or significant delays to the supply of equipment, parts or components.

We depend on certain joint venture, strategic and other partners that may have interests or objectives that conflict with our objectives and such differences could have a negative impact on us.

We have entered into various arrangements with communities or joint venture, strategic or other partners in connection with the operation of our facilities and assets. Certain of these partners may have or develop interests or objectives that are different from, or in conflict with, our objectives. Any such differences could have a negative impact on the Company's ability to realize the anticipated benefits of, or the anticipated increase in the value of facilities or assets subject to, these arrangements. We are sometimes required through the permitting and approval processes to notify and consult with various stakeholder groups, including landowners, Indigenous groups and municipalities. Any unforeseen delays in this process may negatively impact our ability to complete any given facility on time or at all and could result in write-offs or give rise to reputational harm.

Dam and dyke failures may result in lost generating capacity, increased maintenance and repair costs and other liabilities.

A natural or man-made disaster, and certain other events, including natural or induced seismic activity, could potentially cause dam failures at our hydroelectric facilities and various dam sites. The occurrence of dam or dyke failures at any of our facilities could result in a loss of generating capacity, damage to the environment or damages and harm to third parties or the public, and such failures could require us to incur significant expenditures of capital and other resources or expose us to significant liabilities for damages. There can be no assurance that our dam safety program will be able to detect potential dam failures prior to their occurrence or eliminate all adverse consequences in the event of failure. Other safety regulations could change from time to time, potentially impacting our costs and operations. Reinforcing all dams or dykes to enable them to withstand more severe events could require us to incur significant expenditures of capital and other resources. The consequences of dam or dyke failures could have a material adverse effect on us. This includes any increased risk of dam failure due to induced seismic activity triggered by fracking near our hydroelectric facilities, which could increase the risk of dam failure or require the Company to incur potentially significant capital investments to mitigate such risk and that would not otherwise be required.

The power generation industry has certain inherent risks related to worker health and safety, and the environment, that could cause us to suffer unanticipated expenditures or to incur fines, penalties or other consequences material to our business and operations.

The ownership and operation of our power generation assets carry an inherent risk of liability and reputational harm related to worker health and safety, and the environment, including the risk of government-imposed orders to remedy unsafe conditions and/or to remediate or otherwise address environmental contamination, potential penalties for contravention of health, safety and environmental laws, licences, permits and other approvals, and potential civil liability. Compliance with (and any future changes to) health, safety and environmental laws and the requirements of licences, permits and other approvals are expected to remain material to our business. The occurrence of any of these events or any changes, additions to, or more rigorous enforcement of health, safety and environmental laws, licences, permits or other approvals could have a significant impact on our operations and/or result in additional material expenditures. As a consequence, no assurances can be given that additional environmental and workers' health and safety issues relating to presently known or unknown matters will not require unanticipated expenditures, or result in fines, penalties or other consequences (including changes to operations) material to our business and operations.

Climate change and other variations in weather can affect demand for electricity and our ability to generate electricity.

Due to the nature of our business, our earnings are sensitive to weather variations from period to period, as well as long-term changes due to climate change. Variations in winter weather affect the demand for electrical heating requirements. Variations in summer weather affect the demand for electrical cooling requirements. These variations in demand can translate into electricity market price volatility. Variations in precipitation also affect water supplies, which in turn affect our hydroelectric assets. Also, variations in sunlight and wind conditions can have an effect on energy production levels from our solar and wind facilities. Typically, when winters are warmer or summers are cooler, demand for energy is lower than expected, resulting in less electricity consumption than forecasted and often resulting in lower than expected market prices for electricity. Conversely, when winters are colder or summers are warmer, market prices for natural gas or electricity tend to be higher; however, in these circumstances, if we have entered into hedges and are unable to produce or consume the amount of natural gas or electricity that we have hedged we could be required to purchase additional volumes at higher prices to cover our hedge position.

Our generation facilities and their operations are exposed to potential damage and partial or complete loss resulting from environmental disasters (e.g., floods, strong winds, wildfires, earthquakes, tornados and cyclones), equipment failures and other events beyond our control, which could make it difficult for the Company to continue to generate electricity during such periods, and such circumstances could pose threats to the Company's equipment and personnel.

The accumulation of ice on wind turbine blades depends on a number of factors including temperature and ambient humidity, and can have a significant impact on energy yields and could result in the wind turbine experiencing more downtime. Extreme cold temperatures can also impact the ability of wind turbines to operate effectively, and this could result in more downtime and reduced production. Sudden temperature changes can create an increased risk of ice crystals that can pose a number of constraints on our hydro operations.

Climate change is expected to change the volume and timing of precipitation which may impact the ability of hydro facilities to maximize the generation from available water. These changes in flow may result in additional operational costs to manage water through the hydro plants. Variations in weather may be impacted by climate

change resulting in sustained higher temperatures, rising sea levels and altered precipitation patterns that could have an impact on our generating assets. Furthermore, climate change could result in increased variability or sustained long-term changes to our water and wind resources impacting hydroelectric and wind electricity generation, which could adversely affect our revenues and profitability.

Variation in wind levels may negatively impact the amount of electricity generated at our wind facilities.

Given that wind is variable, the amount of electricity produced from our wind facilities is also variable. In addition, the strength and consistency of the wind resource at our wind facilities may vary from what we anticipate due to a number of factors, including the extent to which our site-specific historic wind data and wind forecasts accurately reflect actual long-term wind speeds, strength and consistency, the potential impact of climatic factors, the accuracy of our assumptions relating to, among other things, weather, icing, degradation, site access, wake and wind shear line losses and wind shear, and the potential impact of topographical variations and the potential for electricity losses to occur before delivery.

A reduced amount of wind at the location of one or more of our wind facilities over an extended period may reduce the production from such facilities, as well as any environmental attributes that accrue to us related to that production and reduce our revenues and profitability.

There can be no assurance that we will achieve or be able to adhere to our sustainability targets and any failure to do so may present adverse consequences to our business.

The Company annually establishes sustainability targets to, among things, manage current and emerging material sustainability issues, which include targets relating to decarbonization (refer to the 2025+ Sustainability Targets section of this MD&A for details). The Board of Directors has the discretion to determine the sustainability targets being adopted by the Company and may modify or cancel any previously established sustainability target at any time. The Board of Director's determination to establish, alter or cancel any sustainability target will depend on, among other things: the United Nations Sustainable Development Goals; results of operations; technological considerations; financial condition; market opportunities; legal, regulatory and contractual considerations; and other relevant factors. Further, there is no certainty that the Company will be successful in achieving any particular sustainability target within the stated time frame, or at all. If we are not able to achieve, or adhere to, our sustainability targets, we may not satisfy our stakeholders' current and future expectations, which could negatively impact our reputation and could result in certain investors being unable to hold our common shares.

Many of our activities and properties are subject to environmental regulations, and any liabilities arising under these requirements may materially adversely affect our business.

Our operations are subject to federal, provincial, state and local environmental laws, regulations and guidelines relating to the generation and transmission of electrical and thermal energy and surface mine reclamation (collectively, environmental regulations). These environmental regulations pertain to pollution and the protection of the environment, health and safety, and govern, among other things, air emissions, water usage and discharges, storage, treatment and disposal of waste and other materials, and remediation of sites and responsible land use. These laws and regulations can impose liability and obligations for costs to investigate and remediate contamination without regard to fault, and under certain circumstances liability may be joint and several, resulting in one responsible party being held responsible for the entire obligation. Environmental regulations can also impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transport, treatment and disposal of hazardous substances and waste, and can impose cleanup, disclosure or other responsibilities with respect to spills, releases and emissions of various substances to the environment. Environmental regulations can also require that facilities and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, the relative stringency of environmental regulations can reduce or decline based on political direction, resulting in potentially unstable policy environments at national, state/province and regional levels in Canada, the U.S. and Western Australia, which may impose different compliance requirements or standards on our business. These various compliance standards may impact costs and/or our ability to operate our facilities.

Changes in standards, new or amended regulation, increased enforcement by regulatory authorities, more extensive permitting requirements, an increase in the number and types of assets operated by the Company subject to environmental regulation and the implementation or change to regional, provincial, state and national environmental regulations may impose varying obligations on us in the jurisdictions in which we operate, and could increase our expenditures. To the extent these expenditures cannot be passed through to our customers under our PPAs or otherwise, our costs could be material. In addition, compliance with environmental regulation may result in restrictions on some of our operations. It is

anticipated that compliance costs are at risk of change due to increased political and public attention.

If we do not comply with environmental regulations, regulatory agencies could seek to impose statutory, administrative and/or criminal liabilities on us, curtail our operations, or require significant expenditures on compliance, new equipment or technology, reporting obligations and research and development.

With Bill C-59 we anticipate continued and growing scrutiny by lawyers and other stakeholders relating to sustainability performance. We could face civil liability in the event that private parties seek to impose liability on us for property damage, personal injury or other costs and losses. We cannot guarantee that lawsuits or administrative or investigative actions will not be started against us and otherwise affect our operations and assets. If an action is filed against us or may otherwise affect our operations and assets, we could be required to make substantial expenditures to defend against, or provide evidence of our activities or to bring our Company, our operations and assets into compliance, which could have a material adverse effect on our business.

The estimated reclamation costs applicable to the Company's operations may be inaccurate and could require greater financial resources than currently anticipated. As an owner of mines that were previously in operation, we maintain permits from the applicable regulatory body providing for the authorization of certain mining operations that result in a disturbance of the surface. These requirements sought to limit the adverse impacts of coal mining with more restrictive requirements potentially being adopted from time to time. As an owner of mines that were previously in operation, we may also be required to submit a bond or otherwise secure payment of certain long-term obligations including mine closure or reclamation costs. Surety bond costs have increased in recent years and the market terms of such bonds have generally become more unfavourable. In addition, the number of companies willing to issue surety bonds has decreased. We could be required to self-fund these obligations should we be unable to renew or secure the required surety bonds for our mining operations or if it becomes more economical to do so.

We manage environmental compliance risk by:

- Seeking continuous improvement in numerous performance metrics such as emissions, safety, land and water impacts and environmental incidents;
- Staffing projects during construction and maintenance activities with expert environmental firms to help assure compliance during the project execution process and long term operations of the asset;
- Conducting environmental, health and safety management system audits to assess conformance to our Total Safety Management System, which is designed to continuously improve performance;
- Committing significant experienced resources to work with regulators in Canada, Western Australia and the U.S. to advocate that regulatory changes are well-designed and cost-effective;
- Developing compliance plans that address how to meet or surpass emission standards for GHG, mercury, SO_2 and NOx, which will be adjusted as regulations are finalized;
- Purchasing carbon emissions reduction offsets or credits;
- Investing in renewable energy projects, such as wind, solar and hydro generation and storage technologies; and
- Incorporating change-in-law provisions in contracts that allow recovery of certain compliance costs from our customers.

We are committed to remaining in compliance with all environmental regulations relating to operations and facilities. Compliance with both regulatory requirements and management system standards is regularly audited through our performance assurance policy and results are reported to the GSSC.

The laws and regulations in the various markets in which we operate are subject to change, which may materially adversely affect us.

Most of the markets in which we operate and intend to operate are subject to significant regulatory oversight and control. We are not able to predict whether there will be any further changes in the regulatory environment, including potential carbon and other environmental regulations, changes in market structure or market design, or changes in other laws and regulations. Existing market rules, regulations and reliability standards are often dynamic and may be revised or re-interpreted, and new laws and regulations may be adopted or become applicable to us or our facilities, which could have a material adverse effect on us. Many of our projects must also comply with reliability standards, including those established by the North American Electric Reliability Corporation and Alberta Reliability Standards. Failure to comply with these mandatory reliability standards could result in sanctions, including substantial monetary penalties. We manage these risks systematically through a regulatory and compliance program designed to reduce any potential negative impact on us. However, we cannot guarantee that we will be able to adapt our business in a timely manner in response to any changes in the regulatory regimes in which we operate, and such failure to adapt could have a material adverse effect on our business.

Regulatory authorities may also from time to time audit or investigate our activities in the markets in which we operate or pursue trading. Such audits or investigations may result in sanctions or penalties that may materially affect our future activities, reputation or financial status.

Our facilities are also subject to various licensing and permitting requirements in the jurisdictions in which we operate. Many of these licences and permits need to be renewed from time to time. If we are unsuccessful in obtaining or renewing such licences or permits, or the terms of such licences or permits are changed in a manner that is adverse to our business, we could be materially adversely affected.

Any changes in the rules and regulations of provincial or state public utility commissions or other regulatory bodies in the other markets in which we compete, or may compete in the future, may materially adversely affect us.The laws and regulations in the various markets in which we operate are subject to change, which may materially adversely affect us.

The reduction, elimination or expiration of government subsidies and economic incentives could adversely affect our prospects for growth.

We seek to take full advantage of government policies that promote renewable power generation and enhance the economic feasibility of renewable power projects. Renewable power generation sources currently benefit from various incentives in the form of feed-in tariffs, rebates, tax credits, renewable portfolio standards (such as the U.S. government policy mechanism that supports the adoption of renewable power by setting a targeted percentage of a jurisdiction's total electricity procurement from renewable power) and other incentives throughout the markets in which we participate or intend to participate. If incentives are removed, we would expect to see some reduction in development opportunities, but given that all generators would be in the same boat, the impact may be muted.

We may be adversely affected if our supply of water is materially reduced.

Our hydroelectric and natural gas facilities and our coal-fired facility require continuous water flow for their operation. Shifts in weather or climate patterns, seasonable precipitation, the timing and rate of melting, run-off and other factors beyond our control may reduce the water flow to our facilities. Any material reduction in the water flow to our facilities would limit our ability to produce and market electricity from these facilities and could have a material adverse effect on us. There is an increasing level of regulation respecting the use, treatment and discharge of water, and respecting the licensing of water rights in jurisdictions where we operate. Any such change in regulations could have a material adverse effect on us.

Availability or disruption of fuel supply to our thermal plants could have an adverse impact on the operation of our facilities and our financial condition.

Our gas facilities rely on having adequate supplies of natural gas and our Centralia facility requires adequate supplies of coal to run the facility reliably and at full capacity. As a result, we face the risk of not having adequate fuel supplies available due to insufficient natural gas transportation service, disruptions in fuel supplies due to weather, strikes, lockouts, or breakdowns of equipment, the timing of receiving regulatory approvals or we could be materially adversely affected if the cost of fuel that we must buy to generate electricity increases to a greater degree than the price that we can obtain for the electricity that we sell. Several factors affect the price of fuel, many of which are beyond our control, including:

- Prevailing market prices for fuel;
- Global demand for energy products;
- The cost of carbon and other environmental concerns;
- Weather-related disruptions affecting the ability to deliver fuels or near-term demand for fuels;
- Increases in the supply of energy products in the wholesale power markets;
- Political instability, including the war in Ukraine;
- The extent of fuel transportation capacity, cost of fuel transportation service into our markets or potential rail strikes; and
- The cost of mining or extraction that, in turn, depends on various factors such as labour market pressures, equipment replacement costs and permitting.

Changes in any of these factors may increase our cost of producing power or decrease the amount of revenue received from the sale of power, which could have a material adverse effect on us.

In the event the Company secures more natural gas than required to operate its facilities, the Company may have difficulty reselling such natural gas and it could be exposed to the market price for natural gas in respect of any such resales. There is no certainty that the Company will be successful in reselling or recovering its costs in respect of such resales of natural gas.

As well, the coal used to fuel the Centralia facility is sourced from the Powder River Basin in Montana and Wyoming through contracts to purchase and transport such coal to our Centralia facility. The loss of our suppliers or inability to receive coal at Centralia under our existing

coal contracts at sufficient quantities, or at all, could also significantly affect our ability to serve our customers and have an adverse impact on our financial condition and results of operations. We could face the risk of inadequate supply service due to our reliance on the Pioneer Pipeline and on the ATCO Pipeline as a significant provider of natural gas for our Sundance and Keephills units.

We manage gas supply and price risk by:

- Working to ensure that we have at least two pipelines supplying the gas used in electrical generation in Alberta;
- Contracting for firm gas delivery and supply;
- Monitoring the financial viability of gas producers and pipelines;
- Hedging gas price exposure; and
- Monitoring pipeline maintenance schedules and transportation availability.

We manage coal supply and price risk by:

- Sourcing the coal used at Centralia from different mine sources to ensure sufficient coal is available at a competitive cost;
- Contracting sufficient trains to deliver the coal requirements at Centralia;
- Ensuring coal inventories on hand at Centralia are at appropriate levels for usage requirements;
- Ensuring efficient coal handling and storage facilities are in place so that the coal being delivered can be processed in a timely and efficient manner;
- Monitoring and maintaining coal specifications and carefully matching the specifications mined with the requirements of our facilities;
- Monitoring the financial viability of Centralia suppliers; and
- Hedging diesel exposure in mining and transportation costs.

In managing gas supply risk the company will enter into long term transportation service agreements to ensure that facilities have adequate gas supply. This also could result in the additional risk of of being in a surplus position where some of the transportation capacity may not be needed, and the Company is still required to pay for the unused transportation. To manage this risk the Company will remarket excess natural gas transport capacity in the short-term while seeking long-term or permanent assignments.

Our facilities rely on national and regional transmission systems and related facilities that are owned and operated by third parties and have both regulatory and physical constraints that could impede access to electricity markets.

Our power generation facilities depend on electric transmission systems and related facilities owned and operated primarily by third parties to deliver the electricity that we generate to delivery points where ownership changes and we are paid. The risks associated with the aging transmission infrastructure in the markets where we operate are increasing because new connections to the transmission system are consuming capacity faster than it is being added by new transmission developments.

Further, transmission systems operate with both regulatory and physical constraints that in certain circumstances may impede access to electricity markets. There may be instances in system emergencies in which our power generation facilities are physically disconnected from the power grid, or our production curtailed for periods of time. Most of our electricity sales contracts do not provide for payments to be made if electricity is not delivered.

Our power generation facilities may also be subject to changes in regulations governing the cost and characteristics of use of the transmission and distribution systems to which our power generation facilities are connected. Our power generation facilities in the future may not be able to secure access to this interconnection or transmission capacity at reasonable prices, in a timely fashion or at all, which could then cause delays and additional costs in attempting to negotiate or renegotiate PPAs or to construct new projects. In addition, we may not benefit from preferential arrangements in the future. Any such increased costs and delays could delay the commercial operation dates of any new projects and negatively impact our revenues and financial condition.

Cyberattacks may cause disruptions to our operations and could have a material adverse effect on our business.

We rely on our information technology to process, transmit and store electronic information and data used for the safe operation of our assets. Over the past few years, geopolitical tensions and the pandemic have significantly impacted the cybersecurity ecosystem, increasing the frequency and diversity of cyberattacks, including threats of war-driven cyberattacks (i.e., terrorism) against critical infrastructure and threat actors taking advantage of the pandemic (e.g., charity scams) and hybrid working environments. In the continuously evolving cybersecurity threat landscape, any attacks or breaches of network or information systems may disrupt our business operations or compromise the proprietary, confidential or personal

information of the Company, its customers, partners or others with whom the Company has dealings. Cyberattackers may use a range of techniques, from exploiting vulnerabilities within our user base (social engineering attacks), to using sophisticated malicious code on a single or distributed basis to try to breach our network security controls. We anticipate that the cyber threat landscape will continue to evolve, with increasing threats of ransomware, compromised insider threats, supply chain attacks, advanced targeted phishing and artificial intelligence. Cyber threats originate from various sources and vectors, from nation states, organized hacking groups or malware/ransomware. The cyber threat landscape continues to evolve, as we see cyber threats shift their focus from traditional attacks against perimeter information technology systems, to more effective attacks, such as phishing and ransomware. A successful cyberattack may allow for the unauthorized interception, destruction, use or dissemination of proprietary, confidential or personal information and may cause disruptions to our operations. As information technology /operation technology systems are integral to TransAlta's business operations, the risk of a cybersecurity incident threatens the safety of the public, TransAlta personnel and/or business functions, service delivery, reputation and profitability.

We are subject to regulatory, legislative and business requirements (e.g., North American Electric Reliability Corporation Critical Infrastructure Protection, SOX, Privacy) and also adopt industry endorsed standards and frameworks (e.g., National Institute of Standards and Technology, Critical Infrastructure Projection/Reliability Standards) as they pertain to our cybersecurity program and the implementation of our cybersecurity controls and processes.

While we have cyber insurance, as well as systems, policies, procedures, practices, hardware, software applications and data backups designed to prevent or limit the effect of security breaches of our network and infrastructure, there can be no assurance that these measures will be sufficient and that such security breaches will not occur or, if they do occur, that they will be adequately addressed in a timely manner.

TransAlta has established a comprehensive cybersecurity program to manage cybersecurity risks through effective security practices and structured and tailored plans.

TransAlta maintains compliance to regulatory, legislative, and business requirements (e.g., NERC CIP, SOX, Privacy) by adopting industry-endorsed standards and frameworks (e.g., National Institute of Standards and Technology (NIST), CIP/Reliability Standards) to implement a pragmatic fit-for-purpose cybersecurity program, implementing cybersecurity controls and processes under the following domains:

- Identify: TransAlta conducts comprehensive risk assessments to identify and document the organization's assets, systems and data, as well as potential risks and vulnerabilities.
- Protect: TransAlta implements security controls, policies and procedures to safeguard the organization's assets, systems and data from unauthorized access, use, disclosure, disruption, modification or destruction. This includes implementing access controls, encryption, firewalls and intrusion detection/prevention systems to protect the organization's networks and systems.
- Detect: TransAlta implements incident detection and response capabilities to detect and respond to cyber incidents. This includes monitoring systems, networks and data for suspicious activity.
- Respond: TransAlta has developed incident response plans, procedures and teams, and has provided training and conducted exercises to ensure that these plans and procedures are operating effectively.
- Recover: TransAlta has developed disaster recovery and business continuity plans, and it conducts test exercises of these plans to ensure their effectiveness. This includes identifying critical systems, data and processes to ensure the continuity of business operations, as well as implementing backup and recovery solutions to ensure that the organization's data can be restored in the event of a disaster.

Although complete cyber risk elimination is not achievable given the evolving cyber threat landscape, we believe that the security controls implemented to detect, prevent and respond to a cyber incident significantly reduce TransAlta's cyber risk and potential incident impact to acceptable levels. In addition, cyber insurance is utilized to further manage and transfer residual cyber risk to TransAlta's business. We continue to improve our overall security maturity and defense capabilities against cyber threats and align cybersecurity practices to industry standards, business objectives and regulatory compliance requirements.

Our technology and systems for communication and monitoring may be vulnerable to security breaches or interruptions, which could result in increased operating expenses and other liabilities.

We rely on technology, mainly on computer, telephone, satellite, cellular and related networks and infrastructure, to conduct our business and monitor the production of our generation facilities. These systems and infrastructure could be vulnerable to unforeseen problems including, but not limited to, cyberattacks, breaches, vandalism and theft. Our operations are dependent upon our ability to protect our information and operating technology against damage

from fire, power loss, telecommunications failure or a similar catastrophic event. While we have dedicated resources for maintaining appropriate levels of cybersecurity and we use third-party technology to help protect us against security breaches and cyber incidents, our measures may not be effective and our information technology and infrastructure may be vulnerable to attacks by hackers or breached due to employee error, malfeasance or other disruptions. Any such security breaches and cyber incidents or other disruptions could jeopardize the security of information stored in and transmitted through our systems and network infrastructure, and could result in significant setbacks and potential liabilities and deter future customers. Additionally, we must be able to protect our generation facility infrastructure against physical damage and any service disruptions.

Any damage or failure that causes an interruption in operations could have an adverse effect on our customers. While we have systems, policies, hardware, practices and procedures designed to prevent or limit the effect of failure or interruptions of our generation facilities and infrastructure, there can be no assurance that these measures will be sufficient and that any such failures or interruptions will not occur or, if they do occur, that they will be adequately addressed in a timely manner.

We operate in a highly competitive environment and may not be able to compete successfully.

We operate in a number of Canadian provinces, as well as in the U.S. and Western Australia. These areas of operation are affected by competition ranging from large utilities to small independent power producers, as well as private equity, pension funds, international conglomerates, traditional energy companies and technology firms. In addition, potential customers may look to deploy their own capital to self-supply their own electricity needs. Some competitors have significantly greater financial and other resources than we do. Such competition could have a material adverse effect on our business. Emerging technology affecting the demand, generation, distribution or storage of electricity may also significantly impact our business and ability to compete. Climate change and regulatory incentives are expected to drive innovation and transformation of the power generation sector, including energy production and consumption, and there can be no certainty that the Company will benefit from such innovation or transformation. Furthermore, older facilities may over time be unable to compete with newer more efficient facilities utilizing improvements to existing power technologies and cost-efficient new technologies, including gas turbines with lower heat rates. In Alberta, certain industrial customers rely on behind-the-fence generation; these customers are not being supplied electricity from the grid, which reduces the competitive load in the province and puts downward pressure on pool prices. Further, certain large industrial companies in Alberta operate significant cogeneration facilities, which generate steam required for their operations and often results in large amounts of excess generation being offered to the wholesale electricity market. These cogeneration facilities offer their energy into the market at low prices to ensure it is dispatched, which results in the facility realizing an achieved price close to the average pool price, which potentially puts downward pressure on the pool price and could result in certain of the Company's facilities not being dispatched.

Changes in general economic and market conditions may have a material adverse effect on us.

Adverse changes in general economic and market conditions could negatively impact demand for electricity as well as our revenue, operating costs, the timing and extent of capital expenditures, the net recoverable value of PP&E, financing costs, credit and liquidity risk and counterparty risk which could cause us to suffer a material adverse effect.

We may be unsuccessful in legal actions.

We are occasionally named as a party in various disputes, claims and legal or regulatory proceedings that arise during the normal course of our business. We review each of these claims, including the nature and merits of the claim, the amount in dispute or the remedy claimed and the availability of insurance coverage. There can be no assurance that any particular dispute, claim or proceeding will be resolved in our favour or that our liabilities with respect to such claims will not have a material adverse effect on us. Refer to the Other Consolidated Analysis section of this MD&A for further details.

We may have difficulty raising needed capital in the future, which could significantly harm our business.

To the extent that our sources of cash and cash flow from operations are insufficient to fund our activities or we are unable to divest assets to generate capital, we may need to raise additional funds. Additional financing may not be available when needed, and if such financing is available, it may not be available on terms that are favourable to our business.

Recovery of the capital investment in power projects generally occurs over a long period of time. As a result, we must obtain funds from equity or debt financings, including tax equity transactions, or from government grants, to help finance the acquisition and development of projects and to support the general and administrative costs of operating our business. Our ability to arrange financing, either at the corporate level or at the subsidiary level (including non-

recourse project debt or tax equity), and the costs of such capital are dependent on numerous factors, including: (a) general economic and capital market conditions; (b) credit availability from banks and other financial institutions; (c) investor confidence and the markets in which we conduct operations; (d) our financial performance and/or the expected financial performance of certain assets; (e) our level of indebtedness and compliance with covenants in our debt agreements; (f) our cash flow and/or the expected cash flow of certain assets; and (g) our credit ratings. We are subject to certain financial covenants under our credit facility that could limit the amount of additional debt that the Company could raise in certain circumstances. An inability to raise project debt or tax equity financing could reduce the number of projects that we are able to finance. If we are unable to raise additional funds when needed, we could be required to delay the acquisition and construction of growth projects, reduce the scope of projects, abandon or sell some of our projects or generation facilities, or default on our contractual commitments in the future, any of which could adversely affect our business, financial condition and results of operations.

TransAlta's debt securities will be structurally subordinated to any debt of our subsidiaries that is currently outstanding or may be incurred in the future.

We operate our business through, and a majority of our assets are held by, our subsidiaries, including partnerships. Our results of operations and ability to service indebtedness are dependent upon the results of operations of our subsidiaries and the payment of funds by these subsidiaries to TransAlta in the form of loans, dividends or otherwise. Our subsidiaries may be restricted in their ability to pay amounts due, or make any funds available to TransAlta, whether by dividends, interest payments, loans, advances or other payments. In addition, the payment of dividends and the making of loans, advances and other payments to us by our subsidiaries may be subject to statutory or contractual restrictions or tax withholding amounts. In the event of the liquidation of any subsidiary, the assets of the subsidiary would be used first to repay the indebtedness of the subsidiary, including trade payables or obligations under any guarantees, before being used to pay TransAlta's indebtedness, including any debt securities issued by TransAlta. Such indebtedness and any other future indebtedness of such subsidiaries would be structurally senior for such subsidiary to any debt securities issued by TransAlta.

Our subsidiaries have financed some investments using non-recourse project financing. Each non-recourse project loan is structured to be repaid out of cash flow provided by the project. In the event of a default under a financing agreement that is not secured, the lenders would generally have rights to the related assets. In the event of foreclosure after a default, our subsidiary may lose its equity in the asset or may not be entitled to any cash that the asset may generate.

A downgrade of our credit ratings could materially and adversely affect us.

Rating agencies regularly evaluate us, basing their ratings of our long and short-term debt, along with our issuer rating, on a number of factors. There can be no assurance that one or more of our credit ratings and the corresponding outlooks will not be changed. Our borrowing costs and ability to raise funds are directly impacted by our credit ratings. Credit ratings may be important to suppliers or counterparties when they seek to engage in certain transactions with us. A credit rating downgrade could potentially impair our ability to enter into arrangements with suppliers or counterparties, to engage in certain transactions, and could limit our access to private and public credit markets and increase the costs of borrowing under our existing credit facilities. See Note 15 of our audited consolidated financial statements for the year ended Dec. 31, 2024, which financial statements are incorporated by reference herein.

Changes to our reputation may have a material adverse effect on us.

Reputation risk relates to the risk associated with our business because of changes in opinion from the general public, private stakeholders, governments, financiers and other entities. Our reputation is one of our most valued assets. The potential for harming our reputation exists in every business decision and all risks can have an impact on reputation, which in turn can negatively impact our business and securities. Reputational risk cannot be managed in isolation from other forms of risk. Negative impacts from a compromised reputation could include revenue loss, reduction in our customer base and the decreased value of our securities.

We manage reputation risk by:

- Striving as a neighbour and business partner, in the regions where we operate, to build viable relationships based on mutual understanding leading to workable solutions with our neighbours and other community stakeholders;
- Clearly communicating our business objectives and priorities to a variety of stakeholders on a routine and transparent basis;
- Applying innovative technologies to improve our operations, work environment and environmental footprint;
- Maintaining positive relationships with various levels of government;
- Pursuing sustainable development as a longer-term corporate strategy;

- Ensuring that each business decision is made with integrity and in line with our corporate values;
- Communicating the impact and rationale of business decisions to stakeholders in a timely manner; and
- Maintaining strong corporate values that support reputation risk management initiatives, including the annual Code of Conduct sign-off.

We may fail to meet financial expectations.

Our quarterly revenue, earnings, cash flows and results of operations are difficult to predict and fluctuate from quarter to quarter. Our quarterly results of operations are influenced by a number of factors, including the risks described in this MD&A, many of which are outside of our control and that may cause such results to fall below market expectations. Although we base our planned operating expenses in part on our expectations of future revenue, a significant portion of our expenses are relatively fixed in the short-term. If revenue for a particular quarter is lower than expected, we will likely be unable to proportionately reduce our operating expenses for that quarter, which will adversely affect our results of operations for that quarter.

Our cash dividend payments are not guaranteed.

The payment of dividends is not guaranteed and could fluctuate. The Board of Directors has the discretion to determine the amount and timing of any dividends to be declared and paid to our shareholders. In addition, the payment of dividends on common shares is, in all cases, subject to prior satisfaction of preferential dividends applicable to each series of our first preferred shares. We may alter our dividend on common shares at any time. The Board of Directors' determination to declare dividends will depend on, among other things: results of operations; financial condition; current and expected future levels of earnings; operating cash flow; liquidity requirements; market opportunities; income taxes; maintenance and growth capital expenditures; debt repayments; legal, regulatory and contractual constraints; working capital requirements; taxes payable; and other relevant factors. Our short- and long-term borrowings may prohibit us from paying dividends at any time at which a default or event of default would exist under such debt, or if a default or event of default would exist as a result of paying the dividend.

Over time, our capital and other cash needs may change significantly from our current needs, which could affect whether we pay dividends and the amount of any dividends we may pay in the future. If we continue to pay dividends at the current level, we may not retain a sufficient amount of cash to finance growth opportunities, meet any large unanticipated liquidity requirements or fund our operations in the event of a significant business downturn. The Board of Directors, subject to the requirements of our bylaws and other governance documents, may amend, revoke or suspend our dividends at any time. A decline in the market price or liquidity, or both, of our common shares could result if the Board of Directors reduces or eliminates the payment of dividends.

We are dependent on the operations of our facilities for our cash availability. The actual amount of cash available for dividends to holders of our common shares will depend upon numerous factors relating to each of our generation facilities including: operating performance of our generation facilities; profitability; changes in gross margin; fluctuations in working capital; capital expenditure levels; applicable laws; tax position; financing; compliance with contracts; and contractual restrictions contained in the instruments governing any indebtedness. Any reduction in the amount of cash available for distribution from our generation facilities will reduce the amount of cash available to pay dividends to holders of our common shares.

The market price for our common shares may be volatile.

The market price for our common shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond our control, including: (a) actual or anticipated fluctuations in our results of operations; (b) recommendations by securities research analysts; (c) changes in the economic performance or market valuations of other companies that investors deem comparable; (d) the loss or resignation of executive officers and other key personnel; (e) sales or perceived sales of additional common shares; (f) significant acquisitions or business combinations, strategic partnerships, joint ventures or capital commitments by or involving us or our competitors; and (g) trends, concerns, technological or competitive developments, regulatory changes and other related issues in the power generation industry or our target markets.

Financial markets have experienced significant price and volume fluctuations that have particularly affected the market prices of equity securities of companies and such fluctuations have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of our common shares may decline even if our operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values that may result in impairment losses. Certain institutional investors may base their investment decisions on consideration of our environmental, governance and social practices and performance against such institutions' respective investment guidelines and criteria, and failure to meet such criteria may result in limited or no investment in our common shares by those institutions, which could adversely affect the trading price of our common shares.

We may not be able to extend, renew or replace expiring or terminated PPAs, or other customer contracts at favourable rates or on a long-term basis.

Our ability to extend, renew or replace our existing PPAs or other customer contracts depends on a number of factors beyond our control, including, but not limited to: whether the PPA counterparty has a continued need for energy at the time of the agreement's expiration; the presence or absence of governmental incentives or mandates which prevails market prices; the availability of other electricity sources; the satisfactory performance of our obligations under such PPAs; the regulatory environment applicable to our contractual counterparties at the time; macroeconomic factors present at the time, such as population, business trends, international trade laws, regulations, agreements, treaties, policies or other countries and related energy demand; and the effects of regulation on the contracting practices of our contractual counterparties.

If we are not able to extend, renew or replace on acceptable terms existing PPAs before contract expiration, or if such agreements are otherwise terminated prior to their expiration, we may not have any ability to sell electricity to the market or to other customers. If we are able to sell electricity on an uncontracted basis, we would sell electricity at prevailing market prices that could be materially lower than under the applicable contract. This could result in us having less stable cash flows. If there is no satisfactory market for a project's uncontracted energy, we may decommission the project before the end of its useful life. Any failure to extend, renew or replace a significant portion of our existing PPAs, or other customer contracts, or extending, renewing or replacing them at lower prices or with other unfavourable terms, or the decommissioning of a project, could have a material adverse effect on our business, financial condition, results of operations and ability to pay dividends to our shareholders.

We may fail to fully or effectively hedge our supply and price risk exposure.

We closely monitor the risks associated with changes in electricity and input fuel prices on our future operations and, where we consider it appropriate, use various physical and financial instruments to hedge our assets and operations from such price risks. The efficacy of our risk management and hedging program may be adversely impacted by unanticipated events and costs that we are not able to effectively mitigate, including unanticipated events that impact supply and demand, such as extreme weather and unplanned outages. We may also be adversely impacted if we make incorrect assumptions that were relied upon in establishing our hedges. We are exposed to changes in electricity prices and natural gas prices on purchases of electricity or natural gas from the market to fulfil our supply obligations under these short- and long-term hedge contracts. If we are unable to produce or consume the amount of natural gas or electricity that we have hedged, we could incur losses as we could be required to purchase additional volumes in the market at higher prices in order to cover our hedge position. Comparably, if the market price for electricity is higher than the hedged price we would be subject to the opportunity cost associated with not realizing the higher market price.

We are also exposed to basis risk as certain of our generating facilities receives the "node" price for the electricity it delivers to the grid while the financial PPA for such generating facility settles at the "hub" price. The differences between the "node" price and "hub" price can be significant from time to time.

Trading risks may have a material adverse effect on our business.

Our trading and marketing business frequently involves establishing trading positions in the wholesale energy markets on both a medium-term and short-term basis, and on both an asset and proprietary basis. To the extent that we have long positions in the energy markets, a downturn in market prices will result in losses from a decline in the value of such long positions. Conversely, to the extent that we enter into forward sales contracts to deliver energy that we do not own, or take short positions in the energy markets, an upturn in market prices will expose us to losses as we attempt to cover any short positions by acquiring energy in a rising market.

In addition, from time to time, we may have a trading strategy consisting of simultaneously holding a long position and a short position, from which we expect to earn a profit based on changes in the relative value of the two positions. If, however, the relative value of the two positions changes in a direction or manner that we did not anticipate, we would realize losses from such a paired position.

If the strategy that we use to hedge our exposures to these various risks is not effective, we could incur significant losses. Our trading positions can be impacted by volatility in the energy markets that, in turn, depend on various factors, including weather in various geographical areas and short-term supply and demand imbalances, which cannot be predicted with any certainty. A shift in the energy markets could adversely affect our positions, which could also have a material adverse effect on our business.

We use a number of risk management controls conducted by our risk management group to limit our exposure to risks arising from our trading activities. These controls include risk capital limits, Value at Risk, Gross Margin at Risk, tail risk scenarios, position limits, concentration limits, credit limits and approved product controls. We cannot guarantee

that losses will not occur and such losses may be outside the parameters of our risk controls.

Certain of the contracts to which we are a party require that we provide collateral against our obligations.

We are exposed to risk under certain arrangements, including financial derivative contracts and electricity and natural gas purchase and sale contracts entered into for the purposes of hedging and proprietary trading. The terms and conditions of these contracts may require us to provide collateral when the fair value of these contracts is in excess of any credit limits granted by our counterparties and the contract obliges that we provide the collateral. The change in fair value of these contracts often occurs due to changes in commodity prices. These contracts include: (a) financial derivative contracts when forward commodity prices are more or less than contracted prices, depending on the transactions; (b) purchase agreements, when forward commodity prices are less than contracted prices; and (c) sales agreements, when forward commodity prices exceed contracted prices. Downgrades in our creditworthiness by certain credit rating agencies may decrease the credit limits granted by our counterparties and, accordingly, increase the amount of collateral that we may have to provide. Any increase in the amount of collateral provided by the Company could reduce our liquidity and materially adversely affect us.

If counterparties to our contracts are unable to meet their obligations, we may be materially and adversely affected.

If purchasers of our electricity and steam or other contractual counterparties default on their obligations, we may be materially and adversely affected. While we have procedures and controls in place to manage counterparty credit risk before entering into contracts, all contracts inherently contain default risk. Moreover, while we seek to monitor trading activities to ensure that the credit limits for counterparties are not exceeded, we cannot guarantee that a party will not default. If counterparties to our contracts are unable to meet their obligations, we could suffer a reduction in revenue that could have a material adverse effect on our business.

We manage our exposure to credit risk by:

- Establishing and adhering to policies that define credit limits based on the creditworthiness of counterparties;
- Contract term limits and restrictions on the credit concentration with any specific counterparty;
- Requiring formal sign-off on contracts that include commercial, financial, legal and operational reviews;
- Requiring security instruments, such as parental guarantees, letters of credit and cash collateral or third-party credit insurance if a counterparty goes over its limits. Such security instruments can be collected if a counterparty fails to fulfil its obligation; and
- Reporting our exposure using a variety of methods that allow key decision-makers to assess credit exposure by counterparty. This reporting allows us to assess credit limits for counterparties and the mix of counterparties based on their credit ratings.

If established credit exposure limits are exceeded, we take steps to reduce this exposure, such as by requesting collateral, if applicable, or by halting commercial activities with the affected counterparty. However, there can be no assurances that we will be successful in avoiding losses as a result of a contract counterparty not meeting its obligations.

As needed, additional risk mitigation tactics will be taken to reduce the risk to TransAlta. These risk mitigation tactics may include, but are not limited to, immediate follow-up on overdue amounts, adjusting payment terms to ensure a portion of funds are received sooner, requiring additional collateral, reducing transaction terms and working closely with impacted counterparties on negotiated solutions.

Our credit risk management profile and practices have not changed materially from Dec. 31, 2023. We had no material counterparty losses in 2024. We continue to keep a close watch on changes and trends in the market and the impact these changes could have on our energy trading business and hedging activities and will take appropriate actions as required, although no assurance can be given that we will always be successful.

The following table outlines our maximum exposure to credit risk without taking into account collateral held or right of set-off, including the distribution of credit ratings, as at Dec. 31, 2024:

	Investment grade (per cent)	Non-investment grade (per cent)	Total (per cent)	Total amount ($)
Trade and other receivables[1,2]	87	13	100	**767**
Long-term finance lease receivables	100	—	100	**305**
Risk management assets[1]	58	42	100	**411**
Loan receivable[2]	—	100	100	**25**
Total				**1,508**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) Includes $25 mil ion loan receivable included within other assets with a counterparty that has no external credit rating.

The maximum credit exposure to any one customer for commodity trading operations, including the fair value of open trading positions net of any collateral held, is $77 million (2023 – $23 million).

Because of our multinational operations, we are subject to currency rate risk, tax, regulatory and political risk.

We have exposure to various currencies as a result of our investments and operations in foreign jurisdictions, the earnings from those operations, the acquisition of equipment and services and foreign-denominated commodities from foreign suppliers, and our U.S. and Australian dollar-denominated debt. Our exposures are primarily to the U.S. and Australian currencies, and changes in the values of these currencies relative to the Canadian dollar could negatively impact our operating cash flows or the value of our foreign investments. While we attempt to manage this risk by using hedging instruments, including cross-currency interest rate swaps, forward exchange contracts and matching revenues and expenses by currency at the corporate level, there can be no assurance that these risk management efforts will be effective, and fluctuations in these exchange rates may have a material adverse effect on our business.

In addition to currency rate risk, our foreign operations may be subject to tax, regulatory and political risk. Any change to the regulations governing power generation or the political climate in the countries where we have operations could impose additional costs and have a material adverse effect on us.

We manage our currency rate risk by establishing and adhering to policies that include:

- Hedging our net investments in U.S. operations using U.S. dollar denominated debt;
- Entering into forward foreign exchange contracts to hedge future foreign-denominated expenditures including our U.S. dollar denominated senior debt that is outside the net investment portfolio; and
- Hedging our expected foreign operating cash flows. Our target is to hedge a minimum of 60 per cent of our forecasted foreign operating cash flows over a four-year period, with a minimum of 90 per cent in the current year, 70 per cent in the next year, 50 per cent in the third year and 30 per cent in the fourth year. The U.S. and Australian exposure, net of debt service and sustaining capital expenditures, is managed with forward foreign exchange contracts.

The sensitivity of our net earnings to changes in foreign exchange rates has been prepared using management's assessment that an average $0.03 increase or decrease in the U.S. or Australian currencies relative to the Canadian dollar is a reasonable potential change over the next quarter and is shown below:

Factor	Increase or decrease	Approximate impact on net earnings (millions)
Exchange rate	$0.03	**$20**

We are not able to insure against all potential risks and may become subject to higher insurance premiums.

Our business is exposed to the risks inherent in the construction and operation of electricity generation facilities, such as breakdowns, manufacturing defects, natural disasters, injury, damage to third parties, theft, terrorist attacks, cyberattacks and sabotage. We are also exposed to environmental risks. We maintain insurance policies, covering usual and customary risks associated with our business, with creditworthy insurance carriers. Our insurance policies, however, may not cover losses, or may be subject to limitations in coverage as a result of force majeure, natural disasters, terrorist or cyberattacks or sabotage, armed hostilities, or other perils. Our insurance policies may be subject to increase resulting from climate change, for example due to increased storm severity and frequency. In addition, we generally do not maintain insurance for certain environmental risks, such as environmental contamination. Our insurance policies are subject to annual review by the respective insurers and may not be renewed at all or on similar or favourable terms. A significant uninsured loss or a loss significantly exceeding the limits of our insurance policies or the failure to renew such insurance policies on similar or favourable terms could have a material adverse effect on our business, financial condition and results of operations.

Our insurance coverage may not be available in the future on commercially reasonable terms or adequate insurance limits may not be available in the market. In addition, the insurance proceeds received for loss or damage to any of our generation facilities may not be sufficient to permit us to continue to make payments on our debt.

Provision for income taxes may not be sufficient.

Our operations are complex and located in several countries, and the computation of the provision for income taxes involves tax interpretations, regulations and legislation that are continually changing. In addition, our tax filings are subject to audit by taxation authorities. While we believe that our tax filings have been made in material compliance with all applicable tax interpretations, regulations and legislation, we cannot guarantee that we will not have disagreements with taxation authorities with respect to our tax filings that could have a material adverse effect on our business.

The Company and its subsidiaries are subject to changing laws, treaties and regulations in and between countries. Various tax proposals in the countries we operate in could result in changes to the basis on which deferred taxes are calculated or could result in changes to income or non-income tax expense. There has recently been an increased focus on issues related to the taxation of multinational corporations. A change in tax laws, treaties or regulations, or in the interpretation thereof, could result in a materially higher income or non-income tax expense that could have a material adverse impact on us.

The sensitivity of changes in income tax rates upon our net earnings is shown below:

Factor	Increase or decrease (per cent)	Approximate impact on net earnings (millions)
Tax rate	1	**$3**

If we fail to attract and retain key personnel, we could be materially adversely affected.

The loss of any of our key personnel or our inability to attract, train, retain and motivate additional qualified management and other personnel could have a material adverse effect on our business. Competition for these personnel is intense and there can be no assurance that we will be successful in this regard. If we are unable to successfully negotiate new collective bargaining agreements with our unionized workforce, as required, we will be adversely affected.

While we believe we have a satisfactory relationship with our unionized employees, we cannot guarantee that we will be able to successfully negotiate or renegotiate our collective bargaining agreements on terms agreeable to

TransAlta. In 2024 we successfully renegotiated one collective bargaining agreement.

We expect to renegotiate four collective bargaining agreements in 2025. Any hurdles in negotiating these collective bargaining agreements could lead to higher employee costs and a work stoppage or strike, which could have a material adverse effect on us.

We manage this risk by:

- Possessing a labour relations strategy;
- Applying a human-centric approach that emphasizes the employee experience, including actively improving our workplace culture, focusing on ED&I strategies and offering health and wellness programming and initiatives;
- Focusing on employee learning and development;
- Monitoring industry compensation and aligning salaries with those benchmarks;
- Using incentive pay for non-union roles to align employee goals with corporate goals;
- Monitoring and managing target levels of employee turnover; and
- Ensuring employees have the appropriate training and qualifications to perform their jobs.

We are subject to risks associated with our ownership interests in projects that are under construction, which could result in our inability to complete construction projects on time or at all, and make projects too expensive to complete or cause the return on an investment to be less than expected.

TransAlta has interests in certain projects that have not yet started operations or are under construction. There may be delays or unexpected developments in completing any future construction projects, which could cause the construction costs of these projects to exceed our expectations, result in substantial delays or prevent the project from commencing commercial operations. Various factors could contribute to construction-cost overruns, construction halts or delays or the failure to commence commercial operations, including: delays in obtaining, or the inability to obtain, necessary land rights, permits and licences; delays and increased costs related to the interconnection of new projects to the transmission system; the inability to acquire or maintain land use and access rights; the failure to receive contracted third-party services; interruptions to dispatch at the projects; supply chain disruptions, including as a result of changes in international trade laws, regulations, agreements, treaties, taxes, tariffs, duties or policies of Canada, the U.S. or other countries in which the Company's suppliers are located; work stoppages; labour disputes; weather interferences; unforeseen engineering, environmental and geological problems, including, but not limited to, discoveries of contamination, protected plant or animal species or habitat, archaeological or cultural resources or other environment-related factors; unanticipated cost overruns in excess of budgeted contingencies; and failure of contracting parties to perform under contracts.

In addition, if we or one of our subsidiaries has an agreement for a third party to complete construction of any project, TransAlta is subject to the viability and performance of the third party. Our inability to find a replacement contracting party, if the original contracting party has failed to perform, could result in the abandonment of the construction of such project, while we could remain obligated under other agreements associated with the project, including, but not limited to, offtake PPA's.

We manage project risks by:

- Ensuring all projects follow established corporate processes and policies;
- Identifying key risks during every stage of project development and ensuring mitigation plans are factored into capital estimates and contingencies;
- Reviewing project plans, key assumptions and returns with senior management prior to Board of Director approvals;
- Consistently applying project management methodologies and processes;
- Determining contracting strategies that are consistent with the project scope and scale to ensure key risks, such as labour and technology, are managed by contractors and equipment suppliers;
- Ensuring contracts for construction and major equipment include key terms for performance, delays and quality backed by appropriate levels of liquidated damages;
- Reviewing projects after achieving commercial operation to ensure learnings are incorporated into the next project;
- Negotiating contracts for construction and major equipment to lock in key terms such as price, availability of long lead equipment, foreign currency rates and warranties as much as is economically feasible before proceeding with the project; and
- Entering into labour agreements to provide security around labour cost, supply and productivity.

New technology and artificial intelligence may present emerging risks that could have a material adverse effect on the Company.

We are introducing artificial intelligence and robotics at some of our facilities. The use of artificial intelligence and robotics at our facilities may not yield materially better results, higher outputs or increased productivity and there is no certainty that we will realize benefits from investments in these technologies. Additionally, the use of artificial intelligence is subject to the risk that privacy concerns relating to such technology could deter current and potential customers.

The global energy transition may have an adverse effect on the Company.

The decarbonization of the global energy system in order to achieve net-zero emissions and minimize a global temperature rise poses several risks to TransAlta's business, including but not limited to, changing regulations and policies, market risks from the volatility of and uncertainty of the energy supply and demand, and operational risks from new technologies.

The sensitivity of volumes to our net earnings is shown below:

Factor	Increase or decrease (per cent)	Approximate impact on net earnings (millions)
Availability/production	1	**$17**

Changes in interest rates can impact our borrowing costs and affect our interest rate risk.

Changes in interest rates can impact our borrowing costs. Changes in our cost of capital may also affect the feasibility of new growth initiatives.

At Dec. 31, 2024, approximately 18 per cent (2023 – 14 per cent) of our total long-term debt was subject to changes in floating interest rates through a combination of floating rate debt and interest rate swaps.

We manage interest rate risk by establishing and adhering to policies that include:

- Employing a combination of fixed and floating rate debt instruments;
- Monitoring the mixture of floating and fixed rate debt and adjusting to ensure efficiency; and
- Opportunistically hedging probable debt issuances and outstanding variable rate borrowings using interest rate swaps.

The sensitivity of changes in interest rates upon our net earnings is shown below:

Factor	Increase or decrease (per cent)	Approximate impact on net earnings (millions)
Interest rate	50 bps	**$3**

Disclosure Controls and Procedures

Management is responsible for establishing and maintaining adequate internal control over financial reporting (ICFR) and disclosure controls and procedures (DC&P). For the year ended Dec. 31, 2024, the majority of our workforce supporting and executing our ICFR and DC&P continue to work on a hybrid basis. The Company has implemented appropriate controls and oversight for both in-office and remote work. There has been minimal impact to the design and performance of our internal controls.

ICFR is a framework designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with IFRS. Management has used the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) to assess the effectiveness of the Company's ICFR.

DC&P refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under securities legislation is recorded, processed, summarized and reported within the time frame specified in applicable securities legislation. DC&P include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under applicable securities legislation is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure.

Together, the ICFR and DC&P frameworks provide internal control over financial reporting and disclosure. In designing and evaluating our ICFR and DC&P, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives and as such may not prevent or detect all misstatements and management is required to apply its judgment in evaluating and implementing possible controls and procedures. Further, the effectiveness of ICFR is subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with policies or procedures may change.

In accordance with the provisions of NI 52-109 and consistent with U.S. Securities and Exchange Commission guidance, the scope of the evaluation did not include internal controls over financial reporting of Heartland, which the Company acquired on Dec. 4, 2024. Heartland was excluded from management's evaluation of the effectiveness of the Company's internal control over financial reporting as at Dec. 31, 2024, due to the proximity of the acquisition to year-end. Further details related to the acquisition are disclosed in Note 4 to the Company's Consolidated Financial Statements for the year ended Dec. 31, 2024. Included in the 2024 Consolidated Financial Statements of TransAlta for Heartland are eight per cent per cent and 20 per cent of the Company's total and net assets, respectively, as at Dec. 31, 2024 and one per cent and (5) per cent of the Company's revenues and net earnings, respectively, for the year ended Dec. 31, 2024.

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our ICFR and DC&P as of the end of the period covered by this MD&A. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at Dec. 31, 2024, the end of the period covered by this MD&A, our ICFR and DC&P were effective.

Consolidated Financial Statements

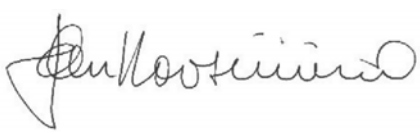
Management's Report

To the Shareholders of TransAlta Corporation

The Consolidated Financial Statements and other financial information included in this annual report have been prepared by management. It is management's responsibility to ensure that sound judgment, appropriate accounting principles and methods, and reasonable estimates have been used to prepare this information. They also ensure that all information presented is consistent.

Management is also responsible for establishing and maintaining internal controls and procedures over the financial reporting process. The internal control system includes an internal audit function and an established business conduct policy that applies to all employees. In addition, TransAlta Corporation (TransAlta or the Company) has a Corporate Code of Conduct that applies to all employees and is signed annually and can be viewed on the Company's website (www.transalta.com). Management believes the system of internal controls, review procedures and established policies provides reasonable assurance as to the reliability and relevance of financial reports. Management also believes that TransAlta's operations are conducted in conformity with the law and with a high standard of business conduct.

The Board of Directors (the Board) is responsible for ensuring that management fulfils its responsibilities for financial reporting and internal controls. The Board carries out its responsibilities principally through its Audit, Finance and Risk Committee (the Committee). The Committee, which consists solely of independent directors, reviews the financial statements and annual report and recommends them to the Board for approval. The Committee meets with management and internal and external auditors to discuss internal controls, auditing matters and financial reporting issues. Internal and external auditors have full and unrestricted access to the Committee. The Committee also recommends the firm of external auditors to be appointed by shareholders.



John Kousinioris

President and Chief Executive Officer



Joel Hunter

Executive Vice President, Finance and Chief Financial Officer

February 19, 2025

Management's Annual Report on Internal Control Over Financial Reporting

To the Shareholders of TransAlta Corporation

The following report is provided by management in respect of TransAlta Corporation's (TransAlta or the Company) internal control over financial reporting (as defined in Rules 13a-15f and 15d-15f under the United States Securities Exchange Act of 1934 and National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings (NI 51-109)).

TransAlta's management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company.

Management uses the Committee of Sponsoring Organizations of the Treadway Commission (COSO) 2013 framework to evaluate the effectiveness of TransAlta's internal control over financial reporting. Management believes that the COSO 2013 framework is appropriate for its evaluation of TransAlta's internal control over financial reporting because it is free from bias, permits reasonably consistent qualitative and quantitative measurements of internal controls, is sufficiently complete so any relevant factors that would alter a conclusion about the effectiveness of the Company's internal controls are not omitted, and is relevant to an evaluation of internal control over financial reporting.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives due to its inherent limitations. Internal control over financial reporting are processes that involve human diligence and compliance that are subject to lapses in judgment and breakdowns resulting from human failures.

Internal control over financial reporting can also be circumvented by collusion or improper overrides. As a result of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis. These inherent limitations are known features of the financial reporting process and it is possible to design safeguards into the process to reduce, though not eliminate, this risk.

In accordance with the provisions of NI 52-109 and consistent with U.S. Securities and Exchange Commission guidance, the scope of the evaluation did not include internal control over financial reporting of Heartland Generation Ltd. and Alberta Power (2000) Ltd. (collectively Heartland), which the Company acquired on Dec. 4, 2024. Heartland was excluded from management's evaluation of the effectiveness of the Company's internal control over financial reporting as at Dec. 31, 2024, due to the proximity of the acquisition to year-end. Further details related to the acquisition are disclosed in Note 4 to the Company's Consolidated Financial Statements for the year ended Dec. 31, 2024. Included in the 2024 Consolidated Financial Statements of TransAlta for Heartland are eight per cent and 20 per cent of the Company's total and net assets, respectively, as at Dec. 31, 2024 and one per cent and (5) per cent of the Company's revenues and net earnings, respectively, for the year ended Dec. 31, 2024.

TransAlta equity accounts for our investment in SP Skookumchuck Investment, LLC (Skookumchuck) in accordance with International Financial Reporting Standards. Management does not have the contractual ability to assess the internal controls of this equity investment. Once the financial information is obtained from Skookumchuck, it falls within the scope of TransAlta's internal controls framework. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of this associate.

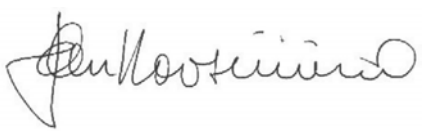
Included in the 2024 Consolidated Financial Statements of TransAlta for equity-accounted investments are one per cent and six per cent of the Company's total and net assets, respectively, as at Dec. 31, 2024, and zero per cent and three per cent of the Company's revenues and net earnings, respectively, for the year ended Dec. 31, 2024.

Changes in Internal Control over Financial Reporting

The Company's internal controls over financial reporting commencing Dec. 4, 2024, include controls designed to result in the complete and accurate consolidation of results attributable to Heartland. There has been no change in the Company's internal control over financial reporting that occurred during the year covered by this Annual Report that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management has assessed the effectiveness of TransAlta's internal control over financial reporting as at Dec. 31, 2024, and has concluded that such internal control over financial reporting was effective.

Ernst & Young LLP, who has audited the Consolidated Financial Statements of TransAlta for the year ended Dec. 31, 2024, has also issued a report on internal control over financial reporting under the standards of the Public Company Accounting Oversight Board. This report is located on the following page of this Annual Report.



John Kousinioris

President and Chief Executive Officer



Joel Hunter

Executive Vice President, Finance and Chief Financial Officer

February 19, 2025

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of TransAlta Corporation

Opinion on Internal Control Over Financial Reporting

We have audited TransAlta Corporation's internal control over financial reporting as of December 31, 2024, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the "COSO criteria"). In our opinion, TransAlta Corporation (the "Company") maintained, in all material respects, effective internal control over financial reporting as of December 31, 2024, based on the COSO criteria.

As indicated in the accompanying Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Heartland Generation Ltd. and Alberta Power (2000) Ltd. which are included in the 2024 consolidated financial statements of the Company and constituted 8% and 20% of total and net assets, respectively, as of December 31, 2024, and 1% and (5)% of revenues and net earnings, respectively, for the year then ended, and the equity accounted joint venture of SP Skookumchuck Investment, LLC which are included in the 2024 consolidated financial statements of the Company and constituted 1% and 6% of total and net assets, respectively, as of December 31, 2024, and 0% and 3% of revenues and net earnings, respectively, for the year then ended. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of Heartland Generation Ltd. and Alberta Power (2000) Ltd. and the equity accounted joint venture of SP Skookumchuck Investment, LLC.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated statements of financial position of TransAlta Corporation as of December 31, 2024 and 2023, the related consolidated statements of earnings, comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2024, and the related notes and our report dated February 19, 2025 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/Ernst & Young LLP

Chartered Professional Accountants

Calgary, Canada

February 19, 2025

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of TransAlta Corporation

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated statements of financial position of TransAlta Corporation (the "Company") as of December 31, 2024 and 2023, the related consolidated statements of earnings, comprehensive income (loss), changes in equity and cash flows, for each of the three years in the period ended December 31, 2024, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2024 and 2023, and the financial performance and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2024, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 19, 2025 expressed an unqualified opinion thereon.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Acquisition of Heartland Generation	
Description of the Matter	As disclosed in notes 2(Q)(XV) and 4 of the consolidated financial statements, the Company completed the acquisition of Heartland Generation Ltd. and Alberta Power (2000) Ltd. (collectively "Heartland") for an aggregate purchase price of $542 million. The acquisition has been accounted for as a business combination under IFRS 3 using the acquisition method and the results of operations have been included in the consolidated financial statements since the date of acquisition. The preliminary purchase price allocation is based on management's best estimates of the assets acquired and liabilities assumed. The fair values of the long-lived assets acquired as at the acquisition date of December 4, 2024 was $412 million. Auditing the fair value of the long-lived assets as part of the preliminary purchase price allocation was identified as a critical audit matter due to the significant estimation uncertainty and judgment applied by management in determining those fair values, primarily due to the sensitivity of the significant assumptions to the future cash flows and the effect that changes in these assumptions would have on the fair values. The estimates with a high degree of subjectivity include market prices, capacity, and determining the appropriate discount rate.
How We Addressed the Matter in Our Audit	We obtained an understanding of management's process for determining the fair value of long-lived assets acquired. We evaluated the design and tested the operating effectiveness of controls over management's review of the long-lived assets acquired, including controls related to the review and approval of the significant estimates used in the determination of the fair value of the long-lived assets. Our audit procedures to test the fair values for a sample of facilities included, among others, comparing the significant assumptions used to estimate cash flows to current contracts with external parties and historical trends and obtaining historical electricity generation data to evaluate future electricity generation capacity forecasts. We evaluated the Company's determination of future sales prices by comparing them to externally available third-party future electricity price estimates. We also involved our internal valuation specialist to assist in our evaluation of the discount rates, which involved benchmarking the inputs against available market data.
Valuation of Long-Lived Assets related to certain cash generating units ("CGU"s) and Goodwill related to the Wind & Solar segment	
Description of the Matter	As disclosed in notes 2(G), 2(H), 2(Q)(II), 7, and 22 of the consolidated financial statements, the Company owns significant Wind & Solar generation assets and has recognized goodwill from historical acquisitions which must be tested for impairment at least annually or when indicators of impairment are present. The carrying value of Goodwill related to the Wind & Solar segment as at December 31, 2024 was $178 million and the recoverable amount of long-lived assets in the Wind & Solar segment that had indicators of impairment or impairment reversal during the year was $540 million. Determining the recoverable amounts for the Wind & Solar segment for the purposes of the goodwill impairment test and of certain CGUs in the Wind & Solar segment with indicators of impairment or impairment reversal ("Wind & Solar CGUs") for the asset impairment test was identified as a critical audit matter due to the significant estimation uncertainty and judgment applied by management in determining the recoverable amount, primarily due to the sensitivity of the significant assumptions to the future cash flows and the effect that changes in these assumptions would have on the recoverable amount. The estimates with a high degree of subjectivity include electricity production, sales prices, cost inputs, and determining the appropriate discount rate.
How We Addressed the Matter in Our Audit	We obtained an understanding of management's process for estimating the recoverable amount of the Wind & Solar segment and the Wind & Solar CGUs. We evaluated the design and tested the operating effectiveness of controls over the Company's processes to determine the recoverable amount. Our audit procedures to test the Company's recoverable amount of the Wind & Solar segment and the Wind & Solar CGUs with indicators of impairment or impairment reversal included, among others, comparing the significant assumptions used to estimate cash flows to current contracts with external parties and historical trends and obtaining historical electricity generation data to evaluate future electricity production forecasts. We assessed the historical accuracy of management's forecasts by comparing them with actual results and performed a sensitivity analysis to evaluate the assumptions that were most significant to the determination of the recoverable amount. We evaluated the Company's determination of future sales prices by comparing them to externally available third-party future electricity price estimates. We also involved our internal valuation specialist to assist in our evaluation of the discount rates, which involved benchmarking the inputs against available market data.

Valuation of Level III Derivative Instruments	
Description of the Matter	As disclosed in notes 2(B), 2(Q)(V) and 14 of the consolidated financial statements, the Company enters into transactions that are accounted for as derivative financial instruments and are recorded at fair value. The valuation of derivative instruments classified as level III are determined using assumptions that are not readily observable. As at December 31, 2024 the fair value of the Company's derivative financial instruments classified as level III was a $153 million net risk management liability. Auditing the determination of fair value of level III derivative instruments that rely on significant unobservable inputs can be complex and relies on judgments and estimates concerning future prices, discount rates, credit value adjustments, liquidity and delivery volumes, and can fluctuate significantly depending on market conditions. Therefore, such determination of fair value was identified as a critical audit matter.
How We Addressed the Matter in Our Audit	We obtained an understanding of the Company's processes and we evaluated and tested the design and operating effectiveness of internal controls addressing the determination and review of inputs used in establishing level III fair values. Our audit procedures included, among others, testing a sample of level III derivative instrument internal models used by management and evaluating the significant assumptions utilized. We also compared management's future pricing assumptions, credit value adjustments, and liquidity assumptions to third-party data as well as comparing terms such as delivery volumes and timing to executed commodity contracts. We compared the delivery volume assumptions to historical information. We performed a sensitivity analysis to evaluate assumptions including future commodity prices, delivery volumes and discount rates. For a sample of level III derivative instruments, we involved our internal valuation specialist to assist in our evaluation of the appropriateness of the fair value by evaluating the key assumptions and methodologies.

/s/Ernst & Young LLP

Chartered Professional Accountants

We have served as auditors of TransAlta Corporation and its predecessor entities since 1947.

Calgary, Canada

February 19, 2025

Consolidated Statements of Earnings

(in millions of Canadian dollars except where noted)

Year ended Dec. 31	2024	2023	2022
Revenues (Note 5)	**2,845**	3,355	2,976
Fuel and purchased power (Note 6)	**939**	1,060	1,263
Carbon compliance (Note 16)	**112**	112	78
Gross margin	**1,794**	2,183	1,635
Operations, maintenance and administration (Note 6)	**655**	539	521
Depreciation and amortization (Note 19, 20, 21 and 27)	**531**	621	599
Asset impairment charges (reversals) (Note 7)	**46**	(48)	9
Taxes, other than income taxes	**36**	29	33
Net other operating income (Note 8)	**(59)**	(47)	(58)
Operating income	**585**	1,089	531
Equity income (Note 9)	**5**	4	9
Finance lease income	**14**	12	19
Interest income	**30**	59	24
Interest expense (Note 10)	**(324)**	(281)	(286)
Foreign exchange gain (loss)	**5**	(7)	4
Gain on sale of assets and other	**4**	4	52
Earnings before income taxes	**319**	880	353
Income tax expense (Note 11)	**80**	84	192
Net earnings	**239**	796	161
Net earnings attributable to:			
TransAlta shareholders	**229**	695	50
Non-controlling interests (Note 12)	**10**	101	111
	239	796	161
Net earnings attributable to TransAlta shareholders	**229**	695	50
Preferred share dividends (Note 29)	**52**	51	46
Net earnings attributable to common shareholders	**177**	644	4
Weighted average number of common shares outstanding in the year (*millions*)	**302**	276	271
Net earnings per share attributable to common shareholders, basic and diluted (Note 28)	**0.59**	2.33	0.01

See accompanying notes.

Consolidated Statements of Comprehensive Income (Loss)

(in millions of Canadian dollars)

Year ended Dec. 31	2024	2023	2022
Net earnings	**239**	796	161
Other comprehensive income (loss)			
Net actuarial gains (losses) on defined benefit plans, net of tax[1]	**9**	(5)	37
Fair value loss on third-party investments, net of tax	**—**	—	(1)
Total items that will not be reclassified subsequently to net earnings	**9**	(5)	36
Gains (losses) on translating net assets of foreign operations, net of tax	**30**	(6)	21
(Losses) gains on financial instruments designated as hedges of foreign operations, net of tax[2]	**(28)**	9	(25)
Gains (losses) on derivatives designated as cash flow hedges, net of tax[3]	**213**	41	(556)
Reclassification of (gains) losses on derivatives designated as cash flow hedges to net earnings, net of tax[4]	**(19)**	58	100
Total items that will be reclassified subsequently to net earnings	**196**	102	(460)
Other comprehensive income (loss)	**205**	97	(424)
Total comprehensive income (loss)	**444**	893	(263)
Total comprehensive income (loss) attributable to:			
TransAlta shareholders	**434**	817	(318)
Non-controlling interests (Note 12)	**10**	76	55
	444	893	(263)

(1) Net of income tax expense of $3 million for the year ended Dec. 31, 2024 (2023 — $1 mil ion recovery, 2022 — $12 mil ion expense).

(2) Net of income tax recovery of $4 million for the year ended Dec. 31, 2024 (2023 — $1 mil ion expense, 2022 — $3 mil ion recovery).

(3) Net of income tax expense of $57 million for the year ended Dec. 31, 2024 (2023 — $10 mil ion expense, 2022 — $138 million recovery).

(4) Net of reclassification of income tax recovery of $4 million for the year ended Dec. 31, 2024 (2023 — $17 million expense, 2022 — $26 million expense).

See accompanying notes.

Consolidated Statements of Financial Position

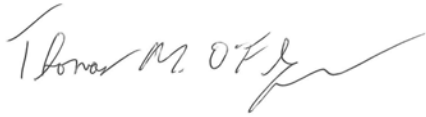
(in millions of Canadian dollars)

As at Dec. 31	2024	2023
Current assets		
Cash and cash equivalents	**337**	348
Restricted cash (Note 25)	**69**	69
Trade and other receivables (Note 13)	**767**	807
Prepaid expenses and other	**68**	48
Risk management assets (Note 14 and 15)	**318**	151
Inventory (Note 16)	**134**	157
Assets held for sale (Note 4 and 18)	**80**	—
	1,773	1,580
Non-current assets		
Investments (Note 9)	**159**	138
Long-term portion of finance lease receivables (Note 17)	**305**	171
Risk management assets (Note 14 and 15)	**93**	52
Property, plant and equipment (Note 19)	**6,020**	5,714
Right-of-use assets (Note 20)	**120**	117
Intangible assets (Note 21)	**281**	223
Goodwill (Note 22)	**517**	464
Deferred income tax assets (Note 11)	**52**	21
Other assets (Note 23)	**179**	179
Total assets	**9,499**	8,659
Current liabilities		
Bank overdraft	**1**	3
Accounts payable, accrued liabilities and other current liabilities (Note 13)	**756**	809
Current portion of decommissioning and other provisions (Note 24)	**83**	35
Risk management iabi ities (Note 14 and 15)	**277**	314
Dividends payable (Note 28 and 29)	**49**	49
Exchangeable securities (Note 3 and 26)	**750**	—
Contingent consideration payable (Note 4)	**81**	—
Current portion of long-term debt and lease iabi ities (Note 25)	**572**	532
	2,569	1,742
Non-current iabi ities		
Credit faci ities, long-term debt and lease liabilities (Note 25)	**3,236**	2,934
Exchangeable securities (Note 3 and 26)	**—**	744
Decommissioning and other provisions (Note 24)	**850**	654
Deferred income tax liabilities (Note 11)	**470**	386
Risk management iabi ities (Note 14 and 15)	**305**	274
Contract liabilities (Note 5)	**24**	10
Defined benefit ob igation and other long-term liabilities (Note 27)	**202**	251
Equity		
Common shares (Note 28)	**3,179**	3,285
Preferred shares (Note 29)	**942**	942
Contributed surplus	**42**	41
Deficit	**(2,458)**	(2,567)
Accumulated other comprehensive income (loss) (Note 30)	**41**	(164)
Equity attributable to shareholders	**1,746**	1,537
Non-controlling interests (Note 12)	**97**	127
Total equity	**1,843**	1,664
Total liabilities and equity	**9,499**	8,659

Commitments and contingencies (Note 37)

See accompanying notes.





On behalf of the Board:

John P. Dielwart
Director

Thomas M. O'Flynn
Chair of Audit, Finance and Risk Committee

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)[1]	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2022	2,863	942	41	(2,514)	(222)	1,110	879	1,989
Net earnings	—	—	—	695	—	695	101	796
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and of tax	—	—	—	—	3	3	—	3
Net gains on derivatives designated as cash flow hedges, net of tax	—	—	—	—	99	99	—	99
Net actuarial losses on defined benefits plans, net of tax	—	—	—	—	(5)	(5)	—	(5)
Intercompany and third-party FVTOCI investments	—	—	—	—	25	25	(25)	—
Total comprehensive income	—	—	—	695	122	817	76	893
Common share dividends (Note 28)	—	—	—	(65)	—	(65)	—	(65)
Preferred share dividends (Note 29)	—	—	—	(51)	—	(51)	—	(51)
Shares purchased under normal course issuer bid (NCIB) (Note 28)	(80)	—	—	(7)	—	(87)	—	(87)
Changes in non-controlling interests in TransAlta Renewables (Note 4)	510	—	—	(625)	(64)	(179)	(630)	(809)
Provision for repurchase of shares under the automatic share purchase plan (Note 28)	(19)	—	—	—	—	(19)	—	(19)
Share-based payment plans and stock options exercised (Note 31)	11	—	—	—	—	11	—	11
Distributions declared to non-control ing interests (Note 12)	—	—	—	—	—	—	(198)	(198)
Balance, Dec. 31, 2023	3,285	942	41	(2,567)	(164)	1,537	127	1,664
Net earnings	**—**	**—**	**—**	**229**	**—**	**229**	**10**	**239**
Other comprehensive income:								
Net gains on translating net assets of foreign operations, net of hedges and tax	**—**	**—**	**—**	**—**	**2**	**2**	**—**	**2**
Net gains on derivatives designated as cash flow hedges, net of tax	**—**	**—**	**—**	**—**	**194**	**194**	**—**	**194**
Net actuarial gains on defined benefits plans, net of tax	**—**	**—**	**—**	**—**	**9**	**9**	**—**	**9**
Total comprehensive income	**—**	**—**	**—**	**229**	**205**	**434**	**10**	**444**
Common share dividends (Note 28)	**—**	**—**	**—**	**(71)**	**—**	**(71)**	**—**	**(71)**
Preferred share dividends (Note 29)	**—**	**—**	**—**	**(52)**	**—**	**(52)**	**—**	**(52)**
Shares purchased NCIB (Note 28)	**(146)**	**—**	**—**	**3**	**—**	**(143)**	**—**	**(143)**
Reversal of provision for repurchase of shares under the automatic share purchase plan (Note 28)	**19**	**—**	**—**	**—**	**—**	**19**	**—**	**19**
Share-based payment plans and stock options exercised (Note 31)	**21**	**—**	**1**	**—**	**—**	**22**	**—**	**22**
Distributions declared to non-control ing interests (Note 12)	**—**	**—**	**—**	**—**	**—**	**—**	**(40)**	**(40)**
Balance, Dec. 31, 2024	**3,179**	**942**	**42**	**(2,458)**	**41**	**1,746**	**97**	**1,843**

(1) Refer to Note 30 for details on components of and changes in, accumulated other comprehensive income (loss).

See accompanying notes.

Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

Year ended Dec. 31	2024	2023	2022
Operating activities			
Net earnings	**239**	796	161
Depreciation and amortization (Note 19, 20, 21 and 27)	**531**	621	599
Gain on sale of assets and other	**(1)**	(3)	(32)
Accretion of provisions (Note 10 and 24)	**50**	48	49
Decommissioning and restoration costs settled (Note 24)	**(41)**	(37)	(35)
Deferred income tax (recovery) expense (Note 11)	**(63)**	34	127
Unrealized loss (gain) from risk management activities	**2**	(36)	385
Unrealized foreign exchange gain	**(29)**	(9)	(82)
Provisions and contract liabilities	**23**	(1)	19
Asset impairment charges (reversals) (Note 7)	**46**	(48)	9
Equity loss (income), net of distributions from investments (Note 9)	**—**	2	(4)
Other non-cash items	**1**	(27)	(3)
Cash flow from operations before changes in working capital	**758**	1,340	1,193
Change in non-cash operating working capital balances (Note 34)	**38**	124	(316)
Cash flow from operating activities	**796**	1,464	877
Investing activities			
Additions to property, plant and equipment (Note 4, 19 and 38)	**(311)**	(875)	(918)
Additions to intangible assets (Note 21 and 38)	**(10)**	(13)	(31)
Restricted cash (Note 25)	**(1)**	1	—
(Advances) repayment from loan receivable (Note 23)	**(1)**	11	18
Acquisitions, net of cash acquired (Note 4)	**(217)**	—	(10)
Investments (Note 9)	**(5)**	(13)	(10)
Proceeds on sale of property, plant and equipment	**4**	29	66
Realized gain on financial instruments	**1**	18	27
Decrease in finance lease receivable	**21**	55	46
Other	**19**	(25)	45
Change in non-cash investing working capital balances	**(20)**	(2)	26
Cash flow used in investing activities	**(520)**	(814)	(741)
Financing activities			
Net increase (decrease) in borrowings under credit facilities (Note 25 and 34)	**143**	(46)	449
Repayment of long-term debt (Note 25 and 34)	**(131)**	(164)	(621)
Issuance of long-term debt (Note 25 and 34)	**—**	39	532
Dividends paid on common shares (Note 28)	**(71)**	(58)	(54)
Dividends paid on preferred shares (Note 29)	**(52)**	(51)	(43)
Repurchase of common shares under NCIB (Note 28)	**(143)**	(87)	(52)
Proceeds on issuance of common shares	**12**	5	3
Realized gain (loss) on financial instruments	**4**	(30)	42
Acquisition of TransAlta Renewables (Note 4)	**—**	(811)	—
Distributions paid to subsidiaries' non-controlling interests (Note 12)	**(40)**	(223)	(187)
Decrease in lease liabilities (Note 25 and 34)	**(6)**	(10)	(9)
Financing fees and other	**(1)**	1	(13)
Change in non-cash financing working capital balances	**(6)**	3	(2)
Cash flow (used in) from financing activities	**(291)**	(1,432)	45
Cash flow (used in) from operating, investing and financing activities	**(15)**	(782)	181
Effect of translation on foreign currency cash	**4**	(4)	6
(Decrease) increase in cash and cash equivalents	**(11)**	(786)	187
Cash and cash equivalents, beginning of year	**348**	1,134	947
Cash and cash equivalents, end of year	**337**	348	1,134
Cash taxes paid	**104**	94	67
Cash interest paid	**269**	277	229
Cash interest received	**30**	54	20

See accompanying notes.

Notes to the Consolidated Financial Statements

(Tabular amounts in millions of Canadian dollars, except as otherwise noted)

1. Corporate Information

A. Description of the Business

TransAlta Corporation (TransAlta or the Company) was incorporated under the *Canada Business Corporations Act* in March 1985 and became a public company in December 1992. The Company's head office is located in Calgary, Alberta.

Operating Segments

Generation Segments

The Company is comprised of four generation segments: Hydro, Wind and Solar, Gas, and Energy Transition. The Company directly or indirectly owns and operates hydro, wind and solar and, natural gas-fired facilities, along with a coal-fired facility and natural gas pipeline operations in Canada, the United States (U.S.) and Western Australia. Transmission in Canada and Western Australia is included within the Hydro and Gas segments in Canada and Western Australia, respectively. The Wind and Solar segment includes the financial results, on a proportionate basis, of our investment in SP Skookumchuck Investment, LLC (Skookumchuck). Segment revenues are derived from the availability and production of electricity and steam as well as ancillary services.

Energy Marketing Segment

The Energy Marketing segment derives revenue and earnings from the trading of electricity, natural gas and environmental products across a variety of North American markets, excluding Alberta.

The Energy Marketing segment also performs services on behalf of certain assets outside of Alberta for the marketing of available generating capacity as well as the procurement of the fuel and transmission needs for the fleet. Contracts of various durations for the forward sales of electricity and for the purchase of natural gas and transmission capacity are utilized. The results of these activities are included in the gross margin of the related generation segment. The Energy Marketing segment allocates charges to recognize the performance of these activities to the applicable generation segments.

Corporate Segment

The Corporate segment includes the Company's central finance, legal, administrative, corporate development, and investor relations functions. Activities and charges directly or reasonably attributable to other segments are allocated to it.

B. Basis of Preparation

These Consolidated Financial Statements have been prepared by management in compliance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

The Consolidated Financial Statements have been prepared on a historical cost basis except for financial instruments, which are measured at fair value, as explained in the following accounting policies.

These Consolidated Financial Statements were authorized for issue by TransAlta's Board of Directors (the Board) on Feb. 19, 2025.

C. Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and the subsidiaries that it controls. Control exists when the Company is exposed, or has rights, to variable returns from its involvement with the subsidiary and has the ability to affect the returns through its power over the subsidiary. The financial statements of the subsidiaries are prepared for the same reporting period and apply consistent accounting policies as the parent company.

2. Material Accounting Policies

The Company has reviewed its material accounting policies. The definition of material that management has used to judgmentally determine disclosure is that information is deemed material if omitting or misstating it could influence decisions users make on the basis of financial information.

A. Revenue Recognition

I. Revenue from Contracts with Customers

The majority of the Company's revenues from contracts with customers are derived from the sale of generation capacity, electricity, thermal energy, environmental attributes and byproducts of power generation. The Company evaluates whether the contracts it enters into meet the definition of a contract with a customer at the inception of the contract and on an ongoing basis if there is an indication of significant changes in facts and circumstances. Contract modifications are accounted for as separate contracts when the consideration for the additional promised goods reflects a stand-alone selling price. Otherwise, contract modifications are accounted for as part of the existing contract. If the additional goods are not considered distinct the transaction price can be affected and adjustments to previously recognized revenue can occur. If the additional goods are distinct, the existing and modified contracts are treated together as a new contract, with impacts reflected prospectively from the modification date, which can include the blending of contract prices. Revenue is measured based on the transaction price specified in a contract with a customer. Revenue is recognized when the control of the goods or services is transferred to the customer. For certain contracts, revenue may be recognized at the invoiced amount, as permitted using the invoice practical expedient, if such amount corresponds directly with the Company's performance to date. The Company excludes amounts collected on behalf of third parties from revenue.

Performance Obligations

Each promised good or service is accounted for separately as a performance obligation if it is distinct. The Company's contracts may contain more than one performance obligation.

Transaction Price

The Company allocates the transaction price in the contract to each performance obligation. The transaction price allocated to performance obligations may include variable consideration. Variable consideration is included in the transaction price for each performance obligation when it is highly probable that a significant reversal of the cumulative variable revenue will not occur. Variable consideration that has previously been constrained is assessed at each reporting period to determine whether the constraint is lifted. The consideration contained in some of the Company's contracts with customers is primarily variable and may include both variability in quantity and pricing, such as: revenues can be dependent upon future production volumes that are driven by customer or market demand or by the operational ability of a plant; revenues can be dependent upon the variable cost of producing energy; revenues can be dependent upon market prices; and revenues can be subject to various indices and escalators.

When multiple performance obligations are present in a contract, the transaction price is allocated to each performance obligation in an amount that depicts the consideration the Company expects to be entitled to in exchange for transferring the good or service. The Company estimates the amount of the transaction price to allocate to individual performance obligations based on their relative stand-alone selling prices, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

Recognition

The nature, timing of recognition of satisfied performance obligations and payment terms for the Company's goods and services are described below:

Good or service	Description
Capacity	Capacity refers to the availability of an asset to deliver goods or services. Customers typically pay for capacity for each defined time period (e.g., monthly) in an amount representative of the availability of the asset for the defined time period. Obligations to deliver capacity are satisfied over time and revenue is recognized using a time-based measure. Contracts for capacity are typically long-term in nature and payments are typically received on a monthly basis.
Contract power	The sale of contract power refers to the delivery of units of electricity to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (e.g., monthly). Obligations to deliver electricity are satisfied over time and revenue is recognized using a units-based output measure (i.e., megawatt hours). Contracts for power are typically long-term in nature and payments are typically received on a monthly basis.
Thermal energy	Thermal energy refers to the delivery of units of steam to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (e.g., monthly). Obligations to deliver steam are satisfied over time and revenue is recognized using a units-based output measure (i.e., gigajoules). Contracts for thermal energy are typically long-term in nature and payments are typically received on a monthly basis.
Environmental attributes	Environmental attributes refers to the delivery of renewable energy certificates, green attributes and other similar items. Customers may contract for environmental attributes in conjunction with the purchase of power, in which case the customer pays for the attributes in the month subsequent to the delivery of the power. Alternatively, customers pay upon delivery of the environmental attributes. Obligations to deliver environmental attributes are satisfied at a point in time, generally upon delivery of the item.
Generation byproducts	Generation byproducts refers to the sale of byproducts from the use of coal in the Company's current U.S. and previous Canadian coal operations. Obligations to deliver byproducts are satisfied at a point in time, generally upon delivery of the item. Payments are received upon satisfaction of delivery of the byproducts.

A contract liability is recorded when the Company receives consideration before the performance obligations have been satisfied. A contract asset is recorded when the Company has rights to consideration for the completion of a performance obligation before it has invoiced the customer. The Company recognizes unconditional rights to consideration separately as a receivable. Contract assets and receivables are evaluated at each reporting period to determine whether there is any objective evidence that they are impaired.

II. Revenue from Other Sources

Merchant Revenue

Revenues from non-contracted capacity (i.e., merchant) include energy payments, at market price, for each MWh produced and are recognized upon delivery.

Lease Revenue

In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above. Where the terms and conditions of the contract result in the customer assuming the principal risks and rewards of ownership of the underlying asset, the contractual arrangement is considered a finance lease, which results in the recognition of finance lease income. Where the Company retains the principal risks and rewards, the contractual arrangement is an operating lease. Rental income, including contingent rents where applicable, is recognized over the term of the contract.

Revenue from Derivatives

Commodity risk management activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, futures contracts and options, which are used to earn revenues and gain market information. The Company also enters into contracts for differences and Virtual Power Purchase Agreements (VPPA). Contracts for differences are financial contracts whereby the Company receives a fixed price per MWh and pays the prevailing real-time energy market price per MWh. With a VPPA, the Company receives the difference between the fixed contract price per MWh and the settled market price. These arrangements meet the definition of a derivative and judgment is applied to determine if the contract meets the "own use" exemption or if derivative treatment is required.

These derivatives are accounted for using fair value accounting. The initial recognition and subsequent changes in fair value affect reported net earnings in the period the change occurs and are presented on a net basis in revenue. The fair values of instruments that remain open at the end of the reporting period represent unrealized gains or losses and are presented on the Consolidated Statements of Financial Position as risk management assets or liabilities. Some of the derivatives used by the Company in trading activities are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using internal valuation techniques or models.

B. Financial Instruments and Hedges

I. Financial Instruments

Classification and Measurement

IFRS 9 introduced the requirement to classify and measure financial assets based on their contractual cash flow characteristics and the Company's business model for the financial asset. All financial assets and liabilities, including derivatives, are recognized at fair value on the Consolidated Statements of Financial Position when the Company becomes party to the contractual provisions of a financial instrument or non-financial derivative contract. Financial assets must be classified and measured at either amortized cost, at fair value through profit or loss (FVTPL), or at fair value through other comprehensive income (loss) (FVTOCI).

Financial assets with contractual cash flows arising on specified dates, consisting solely of principal and interest, and that are held within a business model whose objective is to collect the contractual cash flows, are subsequently measured at amortized cost. Financial assets measured at FVTOCI are those that have contractual cash flows, arising on specific dates, consisting solely of principal and interest, and that are held within a business model whose objective is to collect the contractual cash flows and to sell the financial asset and investments in equity instruments. All other financial assets are subsequently measured at FVTPL.

Financial liabilities are classified as FVTPL when the financial liability is held for trading. All other financial liabilities are subsequently measured at amortized cost.

Funds received under tax equity investment arrangements are classified as long-term debt. These arrangements are used in the U.S. where project investors acquire an equity investment in a project entity, and in return for their investment, are allocated substantially all of the earnings, cash flows and tax benefits (such as production tax credits, investment tax credits, accelerated tax depreciation, as applicable) until they have achieved the agreed upon target rate of return. Once achieved, the arrangements flip, with the Company then receiving the majority of earnings, cash flows and tax benefits. At that time, the tax equity investor's investment is subsequently considered residual equity ownership, with distributions classified as non-controlling interest. In applying the effective interest method to tax equity financings, the Company has made an accounting policy choice to recognize the impacts of the tax attributes in net interest expense.

The Company enters into a variety of derivative financial instruments to manage its exposure to commodity price risk, interest rate risk and foreign currency exchange risk, including fixed price financial swaps, long-term physical power sale contracts, foreign exchange forward contracts, interest rate swap contracts, and designating foreign currency debt as a hedge of net investments in foreign operations.

Derivatives are initially recognized at fair value at the date the derivative contracts are entered into and are subsequently remeasured to their fair value at the end of each reporting period. The resulting gain or loss is recognized in net earnings immediately, unless the derivative is designated and effective as a hedging instrument, in which case the timing of the recognition in net earnings is dependent on the nature of the hedging relationship.

Derivatives embedded in non-derivative host contracts that are not financial assets within the scope of IFRS 9 (e.g., financial liabilities) are treated as separate derivatives when they meet the definition of a derivative, their risks and characteristics are not closely related to those of the host contracts and the host contracts are not measured at FVTPL. Derivatives embedded in hybrid contracts that contain financial asset hosts within the scope of IFRS 9 are not separated, and the entire contract is measured at either FVTPL or amortized cost, as appropriate.

Financial assets are derecognized when the contractual rights to receive cash flows expire. Financial liabilities are

derecognized when the obligation is discharged, cancelled or expired.

Financial assets are also derecognized when the Company has transferred its rights to receive cash flows from the asset or has assumed an obligation to pay the received cash flows to a third party under a "pass-through" arrangement and either transferred substantially all the risks and rewards of the asset, or transferred control of the asset. TransAlta will continue to recognize the asset and any associated liability if it retains substantially all of the risks and rewards of the asset, or retains control of the asset. Continuing involvement that takes the form of a guarantee over the transferred asset is measured at the lower of the original carrying amount of the asset and the maximum amount of consideration that TransAlta could be required to repay.

Financial assets and liabilities are offset and the net amount is reported in the Consolidated Statements of Financial Position if there is a currently enforceable legal right to offset the recognized amounts and there is an intention to settle on a net basis or realize the assets and settle the liabilities simultaneously.

Transaction costs are expensed as incurred for financial instruments classified or designated as FVTPL. For other financial instruments, such as debt instruments, transaction costs are recognized as part of the carrying amount of the financial instrument. The Company uses the effective interest method of amortization for any transaction costs or fees, premiums or discounts earned or incurred for financial instruments measured at amortized cost.

Impairment of Financial Assets

TransAlta recognizes an allowance for expected credit losses for financial assets measured at amortized cost as well as certain other instruments. The loss allowance for a financial asset is measured at an amount equal to the lifetime expected credit loss if its credit risk has increased significantly since initial recognition or if the financial asset is a purchased or originated credit-impaired financial asset. If the credit risk on a financial asset has not increased significantly since initial recognition, its loss allowance is measured at an amount equal to the 12-month expected credit loss.

For trade receivables, lease receivables and contract assets recognized under IFRS 15, TransAlta applies a simplified approach for measuring the loss allowance. Therefore, the Company does not track changes in credit risk but instead recognizes a loss allowance at an amount equal to the lifetime expected credit losses at each reporting date.

The assessment of the expected credit loss is based on historical data and adjusted by forward-looking information that includes third-party default rates over time, dependent on credit ratings.

II. Hedges

Where hedge accounting can be applied and the Company chooses to seek hedge accounting treatment, a hedge relationship is designated as a fair value hedge, a cash flow hedge or a hedge of foreign currency exposures of a net investment in a foreign operation.

A relationship qualifies for hedge accounting if, at inception, it is formally designated and documented as a hedge and the hedging instrument and the hedged item have values that generally move in opposite direction because of the hedged risk. The documentation includes identification of the hedging instrument and hedged item or transaction, the nature of the risk being hedged, the Company's risk management objectives and strategy for undertaking the hedge and how hedge effectiveness will be assessed. The process of hedge accounting includes linking derivatives to specific recognized assets and liabilities or to specific firm commitments or highly probable anticipated transactions.

The Company formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives used are highly effective in offsetting changes in fair values or cash flows of hedged items. If hedge criteria are not met or the Company does not apply hedge accounting, the derivative is recognized at fair value on the Consolidated Statements of Financial Position, with subsequent changes in fair value recorded in net earnings in the period of change.

Fair Value Hedges

In a fair value hedging relationship, the carrying amount of the hedged item is adjusted for changes in fair value attributable to the hedged risk, with the changes being recognized in net earnings. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net earnings.

For fair value hedges relating to items carried at amortized cost, any adjustment to carrying value is amortized through profit or loss over the remaining term of the hedge using the effective interest rate (EIR) method. The EIR amortization may begin as soon as an adjustment exists and no later than when the hedged item ceases to be adjusted for changes in its fair value attributable to the risk being hedged.

If the hedged item is derecognized, the unamortized fair value is recognized immediately in net earnings.

Cash Flow Hedges

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income (loss) (OCI) while any ineffective portion is recognized in net earnings. The cash flow hedge reserve is adjusted to the lower of

the cumulative gain or loss on the hedging instrument and the cumulative change in fair value of the hedged item.

If cash flow hedge accounting is discontinued, the amounts previously recognized in accumulated other comprehensive income (loss) (AOCI) must remain in AOCI if the hedged future cash flows are still expected to occur. Otherwise, the amount will be immediately reclassified to net earnings as a reclassification adjustment. After discontinuation, once the hedged cash flow occurs, any amount remaining in AOCI must be accounted for depending on the nature of the underlying transaction.

Hedges of Foreign Currency Exposures of a Net Investment in a Foreign Operation

When hedging the foreign currency exposure of a net investment in a foreign operation, the effective portion of foreign exchange gains and losses on the hedging instrument is recognized in OCI and the ineffective portion is recognized in net earnings. The related fair values are recorded in risk management assets or liabilities, as appropriate. The amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in the hedged net investment as a result of a disposal, partial disposal or loss of control.

C. Cash and Cash Equivalents

Cash and cash equivalents comprises cash and highly liquid investments with original maturities of three months or less.

D. Inventory

I. Fuel

The Company's inventory balance is composed of coal and natural gas used as fuel, which is measured at the lower of weighted average cost and net realizable value. The cost of natural gas and purchased coal inventory includes all applicable expenditures and charges incurred in bringing the inventory to its existing condition and location.

II. Energy Marketing

Commodity inventories held in the Energy Marketing segment for trading purposes are measured at fair value less costs to sell. Changes in fair value less costs to sell are recognized in net earnings in the period of change.

III. Parts, Materials and Supplies

Parts, materials and supplies are recorded at the lower of cost and measured at moving average costs and net realizable value.

IV. Emission Credits and Allowances

Emission credits and allowances are recorded as inventory at cost. Those purchased for use by the Company are recorded at cost and are carried at the lower of weighted average cost and net realizable value. For emission credits that are not ordinarily interchangeable, the Company records the credits using the specific identification method. Credits granted to or internally generated by, TransAlta are recorded at nil. Emission liabilities are recorded at the estimated compliance cost required by the Company to settle its obligation in excess of government-established caps and targets. Compliance costs that are recoverable under the terms of the contracts with third parties are recognized as revenue from contracts with customers.

Emission credits and allowances that are held for trading and that meet the definition of a derivative are accounted for using the fair value method of accounting. Emission credits and allowances that do not satisfy the criteria of a derivative are accounted for using the accrual method.

E. Property, Plant and Equipment

The Company's investment in property, plant and equipment (PP&E) is initially measured at the original cost of each component at the time of construction, purchase or acquisition. A component is a tangible portion of an asset that can be separately identified and depreciated over its own expected useful life and is expected to provide a benefit for a period in excess of one year. Original cost includes items such as materials, labour, borrowing costs and other directly attributable costs, including the initial estimate of the cost of decommissioning and restoration. Costs are recognized as PP&E if it is probable that future economic benefits will be realized and the cost of the item can be measured reliably. The cost of major spare parts is capitalized and classified as PP&E, as these items can only be used in connection with an item of PP&E.

Planned maintenance is performed at regular intervals. Planned major maintenance includes inspection, repair and maintenance of existing components and the replacement of existing components. Costs incurred for planned major maintenance activities are capitalized in the period maintenance activities occur and are amortized on a straight-line basis over the term until the next major maintenance event. Expenditures incurred for the replacement of components during major maintenance are capitalized and amortized over the estimated useful life of such components.

The cost of routine repairs and maintenance and the replacement of minor parts is charged to net earnings as incurred. Subsequent to initial recognition and measurement at cost, all classes of PP&E continue to be measured using the cost model and are reported at cost

less accumulated depreciation and impairment losses, if any. An item of PP&E or a component is derecognized upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition is included in net earnings when the asset is derecognized. The estimate of the useful life of each component of PP&E is based on current facts and past experience and takes into consideration existing long-term sales agreements and contracts, current and forecasted demand and the potential for technological obsolescence. The useful life is used to estimate the rate at which the component of PP&E is depreciated. PP&E assets are subject to depreciation when the asset is considered to be available for use, which is typically at the start of commercial operations. Insurance spares that are designated as critical for uninterrupted operation in a particular facility are depreciated over the life of that facility, even if the item is not in service. Capital spares begin to be depreciated when the item is put into service. Each significant component of an item of PP&E is depreciated to its residual value over its estimated useful life, generally using straight-line or unit-of-production methods. Estimated useful lives, residual values and depreciation methods are reviewed annually and are subject to revision based on new or additional information. The effect of a change in useful life, residual value or depreciation method is accounted for prospectively.

Estimated remaining useful lives of the components of depreciable assets, categorized by asset class, are as follows:

Hydro generation	1-48 years
Wind and Solar generation	1-30 years
Gas generation	1-33 years
Energy Transition	1-9 years
Capital spares and other	1-48 years

TransAlta capitalizes borrowing costs on capital invested in projects under construction. Upon commencement of commercial operations, capitalized borrowing costs, as a portion of the total cost of the asset, are depreciated over the estimated useful life of the related asset.

F. Intangible Assets

Intangible assets acquired in a business combination are recognized separately from goodwill at their fair value at the date of acquisition. Intangible assets acquired separately are recognized at cost. Internally generated intangible assets arising from development projects are recognized when certain criteria related to the feasibility of internal use or sale and probable future economic benefits of the intangible asset, are demonstrated.

Intangible assets are initially recognized at cost, which is composed of all directly attributable costs necessary to create, produce and prepare the intangible asset to be capable of operating in the manner intended by management.

Software-as-a-service, such as cloud based software, that do not meet the criteria of an intangible asset are expensed as incurred, including implementation costs.

Subsequent to initial recognition, intangible assets continue to be measured using the cost model and are reported at cost less accumulated amortization and impairment losses, if any. Amortization is included in depreciation and amortization in the Consolidated Statements of Earnings.

Amortization commences when the intangible asset is available for use and is computed on a straight-line basis over the intangible asset's estimated useful life. Estimated useful lives of intangible assets may be determined, for example, with reference to the term of the related contract or licence agreement. The estimated useful lives and amortization methods are reviewed annually with the effect of any changes being accounted for prospectively.

Intangible assets consist of power sale contracts with fixed prices higher than market prices at the date of acquisition, software and intangibles under development. Estimated remaining useful lives of intangible assets are as follows:

Software	1-7 years
Power sale contracts	1-17 years

G. Impairment of Tangible and Intangible Assets Excluding Goodwill

At the end of each reporting period, the Company assesses whether there is any indication that PP&E and finite life intangible assets are impaired.

Factors that could indicate that an impairment exists include: significant underperformance relative to historical or projected operating results; significant changes in the manner in which an asset is used, or in the Company's overall business strategy; or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where the Company is not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

The Company's operations, the market and business environment are routinely monitored and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the asset or cash-generating unit

(CGU) to which the asset belongs. The recoverable amount is the higher of an asset's fair value less costs of disposal and its value in use. Fair value is the price that would be received if the asset was sold in an orderly transaction between market participants at the measurement date. In determining fair value, recent market transactions are taken into account. If no such transactions can be identified, an appropriate valuation model such as discounted cash flow is used. Value in use is the present value of the estimated future cash flows expected to be derived from the asset from its continued use and ultimate disposal by the Company. If the recoverable amount is less than the carrying amount of the asset or CGU, an asset impairment charge is recognized in net earnings and the asset's carrying amount is reduced to its recoverable amount.

At each reporting date, an assessment is made whether there is any indication that an impairment charge previously recognized may no longer exist or may have decreased. If such indication exists, the recoverable amount of the asset or CGU to which the asset belongs is estimated and, if there has been an increase in the recoverable amount, the impairment charge previously recognized is reversed. If an impairment charge is subsequently reversed, the carrying amount of the asset is increased to the lesser of the revised estimate of its recoverable amount or the carrying amount that would have been determined (net of depreciation) had no impairment charge been recognized previously. A reversal of an impairment charge is recognized in net earnings.

H. Goodwill

Goodwill arising in a business combination is recognized as an asset at the date control is acquired. Goodwill is measured as the cost of an acquisition plus the amount of any non-controlling interest in the acquiree (if applicable) less the fair value of the related identifiable assets acquired and liabilities assumed.

Goodwill is not subject to amortization, but is tested for impairment at least annually, or more frequently, if an analysis of events and circumstances indicates that a possible impairment may exist. These events could include a significant change in financial position of the CGUs or groups of CGUs to which the goodwill relates or significant negative industry or economic trends. For impairment purposes, goodwill is allocated to each of the Company's CGUs or groups of CGUs that are expected to benefit from the synergies of the business combination in which the goodwill arose. Accordingly, the Company performs its test for impairment, where the recoverable amount of the CGUs or groups of CGUs to which the goodwill relates is compared to its carrying amount for each operating segment. If the recoverable amount is less than the carrying amount, an impairment charge is immediately recognized in net earnings, by first reducing the carrying amount of the goodwill and then by reducing the carrying amount of the other assets in the unit. An impairment charge recognized for goodwill is not reversed in subsequent periods.

I. Income Taxes

The Company uses the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are recognized on the differences between the carrying amounts of assets and liabilities and their respective income tax basis (temporary differences). A deferred income tax asset may also be recognized for the benefit expected from unused tax credits and losses available for carryforward, to the extent that it is probable that future taxable earnings will be available against which the tax credits and losses can be applied. Deferred income tax assets and liabilities are measured based on income tax rates and tax laws that are enacted or substantively enacted by the end of the reporting period and that are expected to apply in the years in which temporary differences are expected to be realized or settled. Deferred income tax is charged or credited to net earnings, except when related to items charged or credited to either OCI or directly to equity. The carrying amount of deferred income tax assets is evaluated at the end of each reporting period and is reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be realized. Unrecognized deferred tax assets are reassessed at each reporting date and are recognized to the extent that it has become probable that future taxable income will allow the deferred income tax asset to be recovered.

Deferred income tax liabilities are recognized for taxable temporary differences arising on investments in subsidiaries, except where the Company is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

Cash taxes paid disclosed on the Consolidated Statements of Cash Flows includes income taxes and taxes paid related to the Part VI.1 tax in Canada for the period.

J. Employee Future Benefits

The Company has defined benefit pension and other post-employment benefit plans. The current service cost of providing benefits under the defined benefit plans is determined using the projected unit credit method prorated based on service. The net interest cost is determined by applying the discount rate to the net defined benefit liability. The discount rate used to determine the present value of the defined benefit obligation and the net interest cost, is determined by reference to market yields at the end of the reporting

period on high-quality corporate bonds with terms and currencies that match the estimated terms and currencies of the benefit obligations. Remeasurements, which include actuarial gains and losses and the return on plan assets (excluding net interest), are recognized through OCI in the period in which they occur. Actuarial gains and losses arise from experience adjustments and changes in actuarial assumptions. Remeasurements are not reclassified to profit or loss, from OCI, in subsequent periods.

Gains or losses arising from either a curtailment or settlement of a defined benefit plan are recognized when the curtailment or settlement occurs. When the restructuring of a benefit plan gives rise to a curtailment and a settlement of obligations, the curtailment is accounted for before the settlement.

In determining whether statutory minimum funding requirements of the Company's defined benefit pension plans give rise to recording an additional liability, letters of credit provided by the Company as security are considered to alleviate the funding requirements. No additional liability results in these circumstances.

Contributions payable under defined contribution pension plans are recognized as a liability and an expense in the period in which the services are rendered.

K. Provisions

Provisions are recognized when the Company has a present obligation (legal or constructive) as a result of a past event, it is probable that the Company will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. A legal obligation can arise through a contract, legislation or other operation of law. A constructive obligation arises from an entity's actions whereby through an established pattern of past practice, published policies or a sufficiently specific current statement, the entity has indicated it will accept certain responsibilities and has thus created a valid expectation that it will discharge those responsibilities. The amount recognized as a provision is the best estimate, remeasured at each period-end, of the expenditures required to settle the present obligation, considering the risks and uncertainties associated with the obligation. Where expenditures are expected to be incurred in the future, the obligation is measured at its present value using a current market-based, risk-adjusted discount rate.

The Company records a decommissioning and restoration provision for all generating facilities and mine sites for which it is legally or constructively required to remove the facilities at the end of their useful lives and restore the plant or mine sites. For some hydro facilities, the Company is required to remove the generating equipment, but is not required to remove the structures.

Initial decommissioning provisions are recognized at their present value when incurred. Each reporting date, the Company determines the present value of the provision using the current discount rates that reflect the time value of money and associated risks. The Company recognizes the initial decommissioning and restoration provisions, as well as changes resulting from revisions to cost estimates and period-end revisions to the market-based, risk-adjusted discount rate, as a cost of the related PP&E (see Note 2(E)) to the extent the related PP&E asset is still in use. Where the related PP&E asset has reached the end of its useful life, changes in the decommissioning and restoration provision are recognized in net earnings. Where the Company expects to receive reimbursement from a third party for a portion of future decommissioning costs, the reimbursement is recognized as a separate asset when it is virtually certain that the reimbursement will be received.

Changes in other provisions resulting from revisions to estimates of expenditures required to settle the obligation or period-end revisions to the market-based, risk-adjusted discount rate are recognized in net earnings.

The accretion of the net present value discount for both the decommissioning and restoration provision and other provisions are charged to net earnings each period and is included in net interest expense.

L. Leases

Under IFRS 16, a contract contains a lease when the customer obtains the right to control the use of an identified asset for a period of time in exchange for consideration.

I. Lessee

The Company enters into lease arrangements with respect to land, building and office space, vehicles and site machinery and equipment. For all contracts that meet the definition of a lease under IFRS 16 in which the Company is the lessee and which are not exempt as short-term or low-value leases, the Company:

- Recognizes right-of-use assets and lease liabilities in the Consolidated Statements of Financial Position;
- Recognizes depreciation of the right-of-use assets and interest expense on lease liabilities in the Consolidated Statements of Earnings; and
- Recognizes the principal repayments on lease liabilities as financing activities and interest payments on lease liabilities as operating activities in the Consolidated Statements of Cash Flows.

For short-term and low-value leases, the Company recognizes the lease payments as operating expenses.

Variable lease payments that do not depend on an index or a rate are not included in the measurement of the lease

liability and the right-of-use asset and are recognized as an expense in the period in which the event or condition that triggers the payments occurs.

Right-of-use assets are initially measured at an amount equal to the lease liability and adjusted for any payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset, or to restore the underlying asset or the site on which it is located, less any lease incentives received.

Lease liabilities are initially measured at the present value of the lease payments that are not paid at commencement and discounted using the Company's incremental borrowing rate or the rate implicit in the lease. The lease liability is remeasured when there is a change in future lease payments arising from a change in an index or rate, or if there is a change in the Company's estimate or assessment of whether it will exercise an extension, termination or purchase option. A corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

The lease term includes periods covered by an option to extend if the Company is reasonably certain to exercise that option and periods covered by an option to terminate if the Company is reasonably certain not to exercise that option.

Right-of-use assets are depreciated over the shorter period of either the lease term or the useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right-of-use asset reflects that the Company expects to exercise the purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset.

The Company has elected to apply the practical expedient that permits a lessee not to separate non-lease components and instead account for any lease and associated non-lease components as a single arrangement.

II. Lessor

Power Purchase Agreements (PPAs) and other long-term contracts may contain, or may be considered, leases where the fulfillment of the arrangement is dependent on the use of a specific asset (e.g., a generating unit) and the arrangement conveys to the customer the right to control the use of that asset.

If the Company determines that the contractual provisions of a contract contain, or are, a lease and result in the customer assuming the principal risks and rewards of ownership of the asset, the arrangement is a finance lease. Assets subject to finance leases are not reflected as PP&E and the net investment in the lease, represented by the present value of the amounts due from the lessee, is recorded in the Consolidated Statements of Financial Position as a financial asset, classified as a finance lease receivable. The payments considered to be part of the leasing arrangement are apportioned between a reduction in the lease receivable and finance lease income. The finance lease income element of the payments is recognized using a method that results in a constant rate of return on the net investment in each period and is reflected in finance lease income on the Consolidated Statements of Earnings.

Where the Company determines that the contractual provisions of a contract contain, or are, a lease and result in the Company retaining the principal risks and rewards of ownership of the asset, the arrangement is an operating lease. For operating leases, the asset is, or continues to be, capitalized as PP&E and depreciated over its useful life.

M. Non-Controlling Interests

Non-controlling interests arise from business combinations in which the Company acquires less than a 100 per cent interest. Non-controlling interests are initially measured at either fair value or at the non-controlling interest's proportionate share of the acquiree's identifiable net assets. The Company determines which measurement is used on a transaction-by-transaction basis. Non-controlling interests also arise from other contractual arrangements between the Company and other parties, whereby the other party has acquired an equity interest in a subsidiary and the Company retains control.

Subsequent to acquisition, the carrying amount of non-controlling interests is increased or decreased by the non-controlling interest's share of subsequent changes in equity and payments to the non-controlling interest. Total comprehensive income (loss) is attributed to the non-controlling interests even if this results in the non-controlling interests having a negative balance.

When the proportion of the equity held by non-controlling interests changes, the carrying amounts of the controlling and non-controlling interests are adjusted to reflect the changes in their relative interests in the subsidiary. Any difference between the amount by which the non-controlling interests are adjusted and the fair value of the consideration paid or received, is recognized directly in equity and attributed to shareholders.

N. Joint Arrangements

A joint arrangement is a contractual arrangement that establishes the terms by which two or more parties agree to undertake and jointly control an economic activity. The Company's joint arrangements are generally classified as two types: joint operations and joint ventures.

A joint operation arises when the parties that have joint control have rights to the assets and obligations for the liabilities relating to the arrangement. Generally, each party takes a share of the output from the asset and each bears an agreed upon share of the costs incurred in respect of the joint operation. The Company reports its interests in joint operations in its Consolidated Financial Statements using the proportionate consolidation method by recognizing its share of the assets, liabilities, revenues and expenses in respect of its interest in the joint operation.

In a joint venture, the venturers do not have rights to individual assets or obligations of the venture. Rather, each venturer has rights to the net assets of the arrangement. The Company reports its interests in joint ventures using the equity method. Under the equity method, the investment is initially recognized at cost and the carrying amount is increased or decreased to recognize the Company's share of the joint venture's net earnings or loss after the date of acquisition. The impact of transactions between the Company and joint ventures is eliminated based on the Company's ownership interest. Distributions received from joint ventures reduce the carrying amount of the investment. Any excess of the cost of an acquisition less the fair value of the recognized identifiable assets, liabilities and contingent liabilities of an acquired joint venture is recognized as goodwill and is included in the carrying amount of the investment and is assessed for impairment as part of the investment.

Investments in joint ventures are evaluated for impairment at each reporting date by first assessing whether there is objective evidence that the investment is impaired. If such objective evidence is present, an impairment charge is recognized if the investment's recoverable amount is less than its carrying amount. The investment's recoverable amount is determined as the higher of value in use and fair value less costs of disposal.

O. Assets Held for Sale

Assets and disposal groups (assets and liabilities disposed of together) are classified as held for sale if their carrying amount will be recovered primarily through a sale as opposed to continued use by the Corporation. Assets and disposal groups classified as held for sale are measured at the lower of their carrying amount and fair value less costs of disposal. Any impairment is recognized in net earnings. Depreciation and equity accounting ceases when an asset or equity investment, respectively, is classified as held for sale. Assets and disposal groups classified as held for sale are reported as current assets and current liabilities in the Consolidated Statements of Financial Position.

P. Business Combinations

Transactions in which the acquisition constitutes a business are accounted for using the acquisition method. Identifiable assets acquired and liabilities assumed, including contingent consideration, are measured at their acquisition date fair values. A business consists of inputs and processes applied to those inputs that have the ability to contribute to the creation of outputs. Goodwill is measured as the excess of the fair value of consideration transferred less the fair value of the net assets acquired. Acquisition-related costs to effect the business combination, with the exception of costs to issue debt or equity securities, are recognized in net earnings as incurred.

The optional fair value concentration test is applied on a transaction-by-transaction basis to permit a simplified assessment of whether an acquired set of activities and assets is not a business. Where substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets, the Company may elect to treat the acquisition as an asset acquisition and not as a business combination.

Q. Significant Accounting Judgments and Key Sources of Estimation Uncertainty

The preparation of financial statements requires management to make judgments, estimates and assumptions that could affect the reported amounts of assets, liabilities, revenues, expenses and disclosures of contingent assets and liabilities during the period. These estimates are subject to uncertainty. Actual results could differ from those estimates due to factors such as fluctuations in interest rates, foreign exchange rates, inflation and commodity prices and changes in economic conditions, legislation and regulations.

In the process of applying the Company's accounting policies, management has to make judgments and estimates about matters that are highly uncertain at the time the estimate is made and that could significantly affect the amounts recognized in the Consolidated Financial Statements. Different estimates with respect to key variables used in the calculations, or changes to estimates, could potentially have a material impact on the Company's financial position or performance. The key judgments and sources of estimation uncertainty are described below:

I. Tariff

On Feb. 1, 2025, the President of the United States issued three executive orders directing the United States to impose new tariffs on imports originating from Canada, Mexico and China. These orders call for additional 25 per cent duty on imports into the United States of Canadian-origin and Mexican-origin products and 10 per cent duty

on Chinese-origin products, except for Canadian energy resources that are subject to an additional 10 per cent duty. On Feb. 3, 2025, a 30-day pause on potential tariffs was implemented. The actual tariffs and their impacts to the Company remain uncertain. The Company is assessing the direct and indirect impacts to its business of such tariffs, retaliatory tariffs or other trade protectionist measures implemented as this situation develops.

II. Impairment of PP&E and Goodwill

Impairment exists when the carrying amount of an asset, CGU or group of CGUs to which goodwill relates exceeds its recoverable amount, which is the higher of its fair value less costs of disposal and its value in use. An assessment is made at each reporting date as to whether there is any indication that an impairment charge may exist or that a previously recognized impairment charge may no longer exist or may have decreased. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if none is available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset.

In estimating either fair value less costs of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, capital expenditures, retirement costs and other related cash inflows and outflows over the life of the facilities. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, changes to regulations and transmission capacity or constraints for the remaining life of the facilities.

Discount rates are determined by employing a weighted average cost of capital methodology that is based on capital structure, cost of equity and cost of debt assumptions based on comparable companies with similar risk characteristics and market data as the asset, CGU or group of CGUs subject to the test. These estimates and assumptions are susceptible to change from period to period and actual results can and often do, differ from the estimates and can have either a positive or negative impact on the estimate of the impairment charge and may be material.

The impairment outcome can also be impacted by the determination of CGUs or groups of CGUs for asset and goodwill impairment testing. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose. The allocation of goodwill is reassessed upon changes in the composition of segments, CGUs or groups of CGUs. To determine CGUs, significant judgment is required to determine what constitutes independent cash flows between power plants that are connected to the same system. The Company evaluates the market design, transmission constraints and the contractual profile of each facility, as well as the Company's own commodity price risk management plans and practices, in order to inform this determination.

With regard to the allocation or reallocation of goodwill, significant judgment is required to evaluate synergies and their impacts. The Company evaluates synergies with regard to opportunities from combined talent and technology, functional organization and future growth potential and considers its own performance measurement processes to make this determination. Information regarding significant judgments and estimates in respect of impairment during 2022 to 2024 is disclosed in Notes 7, 19 and 22.

III. Leases

To determine whether the Company's contracts contain, or are, leases, management must use judgment in assessing whether the contract provides the customer with the right to substantially all of the economic benefits from the use of the asset during the lease term and whether the customer obtains the right to direct the use of the asset during the lease term. For those agreements considered to contain, or be, leases, further judgment is required to determine the lease term by assessing whether termination or extension options are reasonably certain to be exercised. Judgment is also applied in identifying in-substance fixed payments (included) and variable payments that are based on usage or performance factors (excluded) and in identifying lease and non-lease components (services that the supplier performs) of contracts and in allocating contract payments to lease and non-lease components.

For leases where the Company is a lessor, judgment is required to determine if substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with the Company to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant and impact how the Company classifies amounts related to the arrangement as either PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position and therefore the amount of certain items of revenue and expense is dependent upon such classifications. In 2024 and 2023, finance lease receivables were recognized, where it was determined that the significant risks and rewards of ownership of the facilities were transferred to the customer. Information regarding finance leases is disclosed in Note 17.

IV. Income Taxes

Preparation of the Consolidated Financial Statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which the Company operates. The process also involves making an estimate of income taxes currently payable and income taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that the Company's future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. Management uses the Company's long-range forecasts as a basis for evaluation of recovery of deferred income tax assets. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations and legislation to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than the Company's estimates could materially impact the amounts recognized for deferred income tax assets and liabilities. Information regarding the impacts of the Company's tax policies is disclosed in Note 11.

V. Financial Instruments and Derivatives

The Company's financial instruments and derivatives are accounted for at fair value, with the initial and subsequent changes in fair value affecting earnings in the period the change occurs. The fair values of financial instruments and derivatives are classified within three levels, with Level III fair values determined using inputs for the asset or liability that are not readily observable. Transfers between levels of the fair value hierarchy are deemed to have occurred at the end of the reporting period in which the event or change in circumstances that caused the transfer occurred. These fair value levels are outlined and discussed in more detail in Note 14. Some of the Company's fair values are included in Level III because they are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available and require the use of internal valuation techniques or models to determine fair value.

The determination of the fair value of these contracts and derivative instruments can be complex and relies on judgments and estimates concerning future prices, volatility and liquidity, among other factors. These fair value estimates may not necessarily be indicative of the amounts that could be realized or settled and changes in these assumptions could affect the reported fair value of financial instruments. Fair values can fluctuate significantly and can be favourable or unfavourable depending on current market conditions. Judgment is also used in determining whether a highly probable forecasted transaction designated in a cash flow hedge is expected to occur based on the Company's estimates of pricing and production to allow the future transaction to be fulfilled.

When the Company enters into contracts to buy or sell non-financial items, such as certain commodities, and the contracts can be settled net in cash, the Company must use judgment to evaluate whether such contracts were entered into and continue to be held for the purposes of the receipt or delivery of the commodity in accordance with the Company's expected purchase, sale or usage requirements (i.e., normal purchase and sale). If this assertion cannot be supported, initially at contract inception and on an ongoing basis, the contracts must be accounted for as derivatives and measured at fair value, with changes in fair value recognized in net earnings. In supporting the normal purchase and sale assertion, the Company considers the nature of the contracts, the forecasted demand and supply requirements to which the contracts relate and its past practice of net settling other similar contracts, which may taint the normal purchase and sale assertion. The Company also enters into PPAs and contracts for differences and judgment is applied to determine if the contract meets the "own use" exemption or if derivative treatment is required.

VI. Project Development Costs

Project development costs are recognized in operating expenses until construction of a facility or acquisition of an investment is likely to occur, there is reason to believe that future costs are recoverable and that efforts will result in future value to the Company, at which time the costs incurred subsequently are included in PP&E or other assets. The appropriateness of capitalization of these costs is evaluated each reporting period and amounts capitalized for projects no longer probable of occurring or when there is uncertainty of timing of when the projects will proceed are charged to net earnings. Management is required to use judgment to determine if there is reason to believe that future costs are recoverable and that efforts will result in future value to the Company when determining the amount to be capitalized. Information regarding project development costs is disclosed in Note 23 and information on the write-off of project development costs is disclosed in Note 7.

VII. Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(K). Initial decommissioning provisions and subsequent changes thereto are determined using the Company's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. The estimated cash expenditures are present valued using a current, risk-adjusted, market-

based, pre-tax discount rate. A change in estimated cash flows, market interest rates or timing could have a material impact on the carrying amount of the provision. Information regarding significant judgments and estimates made during 2022 to 2024 in respect of decommissioning and restoration provisions is disclosed in Notes 7, 19 and 24.

VIII. Useful Life of PP&E

Each significant component of an item of PP&E is depreciated over its estimated useful life. Estimated useful lives are determined based on current facts and past experience and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, the potential for technological obsolescence and regulations. The useful lives of PP&E are reviewed at least annually to ensure they continue to be appropriate. Information on changes in useful lives of facilities is disclosed in Note 19.

IX. Employee Future Benefits

The Company provides pension and other post-employment benefits, such as health and dental benefits, to employees. The cost of providing these benefits is dependent upon many factors, including actual plan experience and estimates and assumptions about future experience.

The liability for pension and post-employment benefits and associated costs included in annual compensation expenses are impacted by estimates related to:

- Employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans and earnings on plan assets;
- The effects of changes to the provisions of the plans; and
- Changes in key actuarial assumptions, including rates of compensation and health-care cost increases and discount rates.

Due to the complexity of the valuation of pension and post-employment benefits, a change in the estimate of any one of these factors could have a material effect on the carrying amount of the liability for pension and other post-employment benefits or the related expense. These assumptions are reviewed annually to ensure they continue to be appropriate. Disclosures on employee future benefits are disclosed in Note 32.

X. Other Provisions

Where necessary, the Company recognizes provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation and force majeure claims. These provisions and subsequent changes thereto, are determined using the Company's best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized. More information is disclosed in Notes 8 and 24 with respect to other provisions.

XI. Revenue from Contracts with Customers

Where contracts contain multiple promises for goods or services, management exercises judgment in determining whether goods or services constitute distinct goods or services or a series of distinct goods that are substantially the same and that have the same pattern of transfer to the customer. The determination of a performance obligation affects whether the transaction price is recognized at a point in time or over time. Management considers both the mechanics of the contract and the economic and operating environment of the contract to determine whether the goods or services in a contract are distinct.

In determining the transaction price and estimates of variable consideration, management considers the past history of customer usage in estimating the goods and services to be provided to the customer. The Company also considers the historical production levels and operating conditions for its variable generating assets. The Company's contracts generally outline a specific amount to be invoiced to a customer associated with each performance obligation in the contract. Where contracts do not specify amounts for individual performance obligations, the Company estimates the amount of the transaction price to allocate to individual performance obligations based on their stand-alone selling price, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

The satisfaction of performance obligations requires management to make judgments as to when control of the underlying good or service transfers to the customer. Determining when a performance obligation is satisfied affects the timing of revenue recognition. Management considers both customer acceptance of the good or service and the impact of laws and regulations such as certification requirements, to determine when this transfer occurs.

When contracts are modified, management must exercise judgment to determine, depending upon the facts and circumstances of the changes to the contract, whether the modification is accounted for as a new contract or as part of the existing contract. If it is required to be accounted for as part of the existing contract the transaction price can be affected and adjustments to previously recognized revenue can occur, or the impacts can be reflected prospectively from the modification date.

Management also applies judgment in determining whether the invoice practical expedient permits recognition of revenue at the invoiced amount if that invoiced amount corresponds directly with the entity's performance to date.

XII. Classification of Joint Arrangements

Upon entering into, or acquiring an interest in, a joint arrangement, the Company must classify it as either a joint operation or joint venture, and this classification affects the accounting for the joint arrangement. In making this classification, the Company exercises judgment in evaluating the terms and conditions of the arrangement to determine whether the parties have rights to the assets and obligations or rights to the net assets. Factors such as the legal structure, contractual arrangements and other facts and circumstances, such as where the purpose of the arrangement is primarily for the provision of the output to the parties and when the parties are substantially the only source of cash flows for the arrangement, must be evaluated to understand the rights of the parties to the arrangement.

XIII. Significant Influence

Upon entering into an investment, the Company must classify it as either an investment in an associate or an investment under IFRS 9. In making this classification, the Company exercises judgment in evaluating whether the Company has significant influence over the investee. Significant influence is the power to participate in the financial and operating policy decisions of the investee, but is not control or joint control over those policies. If the Company holds 20 per cent or more of the voting rights in the investee, it is presumed that the entity has significant influence, unless it can be clearly demonstrated that this is not the case. Other factors such as representation on the Board, participation in policy-making processes, material transactions between the Company and investee, interchange of managerial personnel or providing essential technical information are considered when assessing if the Company has significant influence over an investee.

XIV. Change in Estimates

During the year ended Dec. 31, 2024, there were changes in estimates relating to asset impairment charges (reversals) (Note 7), asset useful lives and depreciation (Note 19), decommissioning and other provisions (Note 24) and defined benefit obligation (Note 27). During the year ended Dec. 31, 2023, there were changes in estimates relating to asset impairment charges (reversals) (Note 7), useful lives (Note 19), decommissioning and other provisions (Note 24) and defined benefit obligation (Note 27).

XV. Fair Value of Assets Acquired and Liabilities Assumed in Business Combination

The fair value of assets acquired and liabilities assumed, including contingent consideration, is estimated based on information available at the date of acquisition. While Management uses best estimates and assumptions to accurately value assets acquired and liabilities assumed at the date of acquisition, as well as any contingent consideration, estimates are inherently uncertain and subject to refinement.

Accounting for business combinations requires significant judgement, estimates and assumptions at the acquisition date. In developing estimates of fair values at the acquisition date, Management utilize a variety of factors including market data, market prices, capacity, historical and future expected cash flows, growth rates and discount rates. Information regarding business combinations has been included in Note 4.

3. Accounting Changes

A. Current Accounting Changes

Amendments to IAS 1 — Non-current Liabilities with Covenants and Classification of Liabilities as Current or Non-current

In October 2022, the IASB issued Non-current Liabilities with Covenants, which amends IAS 1 Presentation of Financial Statements, to clarify how conditions with which an entity must comply within 12 months after the reporting period affect the classification of a liability. In January 2020, the IASB issued Classification of Liabilities as Current or Non-current, which amends IAS 1 Presentation of Financial Statements regarding the classification of liabilities as current or non-current, clarifying that contractual rights and conditions existing at the end of the reporting period are relevant in determining whether the Company has a right to defer settlement of a liability by at least 12 months.

Additionally, the IASB clarified that the classification of a liability is unaffected by the likelihood that an entity will exercise its deferral right. The amendments are applied retrospectively, effective for annual periods beginning on or after Jan. 1, 2024, and were adopted by the Company on that date.

The Company has an Investment Agreement whereby Brookfield Renewable Partners or its affiliates (collectively, Brookfield) invested $750 million in TransAlta through the purchase of exchangeable securities (Exchangeable Securities), which are exchangeable into an equity ownership interest in TransAlta's Alberta hydro assets in the future. On Jan. 1, 2024, the Company reclassified the Exchangeable Securities from non-current liabilities to current liabilities as the conversion option can be exercised at any time after Dec. 31, 2024, although there is no obligation to deliver cash equiva ent resources and the holder cannot call for repayment. This accounting is consistent with the amendment.

B. Future Accounting Changes

The Company closely monitors both new accounting standards and amendments to existing accounting standards issued by the IASB. The following standards have been issued but are not yet in effect.

Amendments to IFRS 9 and IFRS 7 — Nature-Dependent Electricity Contracts

On Dec. 18, 2024, the IASB issued amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosure to improve reporting of the financial effects of nature-dependent electricity (e.g., wind and solar) contracts, which are often structured as power purchase agreements. Under these contracts, the amount of electricity generated can vary based on uncontrollable factors such as weather conditions. The amendments clarify the application of own-use requirements, permit hedge accounting if these contracts are used as hedging instruments and add new disclosure requirements about the effect of these contracts on a company's financial performance and cash flows. The amendments are effective for annual reporting periods beginning on or after Jan. 1, 2026. The Company is currently evaluating the impacts to the financial statements.

Amendments to IFRS 7 and IFRS 9 — Classification and Measurement of Financial Instruments

On May 29, 2024, the IASB issued Amendments to the Classification and Measurement of Financial Instruments effective Jan. 1, 2026 impacting IFRS 7 and 9. The IASB amended the requirements related to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets, including those with ESG-linked features. The Company is currently evaluating the impacts to the financial statements.

IFRS 18 — Presentation and Disclosure in Financial Statements

On April 9, 2024, the IASB issued a new standard, IFRS 18 *Presentation and Disclosure in Financial Statements*, which introduced new requirements for improved comparability in the statement of profit or loss, enhanced transparency of management-defined performance measures and more useful grouping of information in the financial statements. The standard is effective for annual reporting periods beginning on or after Jan. 1, 2027. The Company is currently evaluating the impacts to the financial statements.

C. Comparative Figures

Certain comparative figures have been reclassified to conform to the current period's presentation. These reclassifications did not impact previously reported net earnings.

4. Business Acquisitions

Acquisition of Heartland Generation

On Dec. 4, 2024 (Acquisition Date), the Company acquired all issued and outstanding common shares of Heartland Generation Ltd. and Alberta Power (2000) Ltd. (collectively, Heartland) from Energy Capital Partners (ECP) (the Acquisition). The Acquisition, which includes Heartland's entire business operations in Alberta and British Columbia, was completed for an aggregate purchase price of $542 million. This amount was adjusted for the reduction of $95 million to reflect the economic benefit of the Heartland business arising since Oct. 31, 2023 and a working capital adjustment of $2 million. The Acquisition included the assumption of long-term debt at the Acquisition Date of $232 million and Heartland's cash and cash equivalents of $276 million, resulting in a purchase price of $493 million. The Acquisition was funded through a combination of cash on hand and draws on the Company's credit facilities.

Heartland owns and operates generation assets consisting of 507 MW of cogeneration, 387 MW of contracted and merchant peaking generation, 950 MW of natural gas-fired thermal generation, transmission capacity and a development pipeline that includes the 400 MW Battle River Carbon Hub.

In order to meet the requirements of the federal Competition Bureau, TransAlta entered into a consent agreement with the Commissioner of Competition pursuant to which TransAlta agreed to divest Heartland's Poplar Hill and Rainbow Lake assets with combined gross installed capacity of 97 MW following closing (the Planned Divestiture). ECP will be entitled to receive the proceeds from the Planned Divestiture and net cash flows of these assets arising from Nov. 13, 2024 to the date of the sale. The sales process for these assets is in progress. The Company has no residual financial risk on the sale.

The acquired tangible and intangible assets and assumed liabilities are recorded at their estimated fair values at the date of the Acquisition. The total consideration was allocated to the tangible and intangible assets acquired and liabilities assumed, with any excess recorded as goodwill.

The preliminary purchase price allocation reflects management's best estimate of the fair value of the acquired assets and liabilities based on the analysis of information obtained to date. Management is continuing to obtain specific information to support the valuation of the environmental compliance liabilities, decommissioning provision, property, plant and equipment, and deferred taxes. Any adjustments to the purchase price allocation will be made as soon as practicable but no later than one year from the date of acquisition.

The following table summarizes the preliminary fair values that were assigned to the net assets acquired as at the Acquisition Date.

	Dec. 4, 2024
Current Assets and Non-Current Assets	
Cash and cash equivalents	276
Trade and other receivables	126
Risk management assets current	7
Prepaid expenses and other	104
Assets held for sale (Note 18)	80
Long-term portion of finance lease receivables (Note 17)	107
Risk management assets non-current	9
Property, plant and equipment and Right-of-use assets (Note 19 and 20)	413
Intangible assets (Note 21)	57
Other assets	2
Deferred income tax assets (Note 11)	41
Current Liabilities and Non-Current Liabilities	
Accounts payable and accrued liabilities	193
Risk management liabilities current	3
Current portion of decommissioning (Note 24)	4
Current portion of other provisions (Note 24)	15
Current portion of contract liabilities (Note 5)	3
Current portion of long-term debt and lease liabilities (Note 25)	28
Credit facilities, long-term debt and lease liabilities (Note 25)	204
Decommissioning non-current portion (Note 24)	97
Other provisions non-current (Note 24)	40
Deferred income tax liabilities (Note 11)	108
Risk management liabilities non-current	1
Contract liabilities non-current (Note 5)	3
Total identifiable net assets at fair value	523
Goodwill arising on acquisition (Note 22)	51
Net assets acquired	574
Cash consideration	493
Contingent consideration payable	81
Total purchase consideration transferred	574

As discussed above, the Company has agreed to pay contingent consideration to ECP for the proceeds from the Planned Divestiture and net cash flows of these assets arising from Nov. 13, 2024, to the date of the sale. The $81 million of contingent consideration recognized in the purchase price represents the fair value of contingent consideration at the date of acquisition. The fair value was determined based on expected sale proceeds and net cash flows from operations. The Planned Divestiture is classified and recorded as assets and liabilities held for sale.

Goodwill of $51 million recognized on the transaction is a result of deferred tax liabilities recognized on the transaction, which are recorded at the Company's effective tax rate without discounting, and from value attributed to the existence of an assembled workforce. None of the goodwill is expected to be deductible for tax purposes.

Acquisition-related expenses incurred were approximately $24 million for the year ended Dec. 31, 2024 and are included in operating, maintenance and administrative expenses recognized in the Consolidated Statements of Earnings.

Revenue generated by the Acquisition for the period Dec. 4, 2024 to Dec. 31, 2024 was $34 million. Net loss before taxes for the same period was $11 million. Had Heartland been acquired at the beginning of the year, the assets would have contributed an estimated $598 million to revenues and $66 million to net earnings before taxes.

Acquisition of TransAlta Renewables

On Oct. 5, 2023, the Company completed the acquisition of the outstanding common shares of TransAlta Renewables not already owned, directly or indirectly, by the Company. The consideration paid totalled $1.3 billion, comprising $800 million of cash and 46 million common shares of the Company valued at $514 million, based on an $11.06 closing price of the Company's shares on the Toronto Stock Exchange on Oct. 4, 2023.

Transaction costs of $11 million incurred to effect the acquisition have been charged, net of income tax, against common shares ($4 million) and deficit ($7 million) on closing of the acquisition.

Since the Company retained control of TransAlta Renewables, the acquisition was accounted for as an equity transaction. On closing of the transaction, non-controlling interests was reduced by $630 million and accumulated other comprehensive loss increased by $64 million to eliminate the balances previously attributed to non-controlling interest holders of TransAlta Renewables. The difference between consideration paid and these amounts was recognized in deficit.

The Company's syndicated credit facilities were amended to effectively consolidate the TransAlta Renewables syndicated credit facility and non-committed demand facility into the TransAlta credit facilities. The cash drawings on the TransAlta Renewables' syndicated credit facility were repaid and the outstanding letters of credit were transferred to the TransAlta non-committed demand facility. The TransAlta Renewables' credit facilities were then terminated. This resulted in the TransAlta syndicated credit facility increasing by $700 million to approximately $2.0 billion. Refer to Note 25.

5. Revenue

A. Disaggregation of Revenue

The majority of the Company's revenues are derived from the sale of power, capacity and environmental and tax attributes, leasing of power facilities and from asset optimization activities, which the Company disaggregates into the following groups for the purpose of determining how economic factors affect the recognition of revenue.

Year ended Dec. 31, 2024	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate[1]	Total
Revenues from contracts with customers							
Power and other	36	242	494	12	—	—	784
Environmental and tax attributes[2]	61	77	2	—	—	(34)	106
Revenue from contracts with customers	97	319	496	12	—	(34)	890
Revenue from derivatives and other trading activities[3]	16	(69)	282	311	168	—	708
Revenue from merchant sales	287	71	546	291	—	—	1,195
Other[4]	9	15	26	2	—	—	52
Total revenue	409	336	1,350	616	168	(34)	2,845
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	61	28	—	12	—	(34)	67
Over time	36	291	496	—	—	—	823
Total revenue from contracts with customers	97	319	496	12	—	(34)	890

(1) The elimination of intercompany sales is reflected in the Corporate segment.

(2) The environmental and tax attributes represent environmental attributes and production tax transfer sales not bundled with power and other sales.

(3) Represents realized and unrealized gains or losses from hedging and derivative positions. Volatility and pricing in commodity markets can vary significantly from period to period and impact movements in derivative positions.

(4) Other revenue includes production tax credits related to U.S. wind facilities subject to tax equity financing arrangements, total lease income from long-term contracts that meet the criteria of operating leases and other miscellaneous revenues.

Year ended Dec. 31, 2023	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Revenues from contracts with customers							
Power and other[1]	30	204	400	12	—	—	646
Environmental and tax attributes[2]	14	26	—	—	—	—	40
Revenue from contracts with customers	44	230	400	12	—	—	686
Revenue from derivatives and other trading activities[1][3]	44	(16)	(172)	251	220	—	327
Revenue from merchant sales	434	104	1,247	488	—	—	2,273
Other[4]	11	18	39	—	—	1	69
Total revenue	533	336	1,514	751	220	1	3,355
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	14	26	—	12	—	—	52
Over time	30	204	400	—	—	—	634
Total revenue from contracts with customers	44	230	400	12	—	—	686

(1) In the Wind and Solar segment, $14 million of mark-to-market losses were reclassified from revenue from contracts with customers to revenue from derivatives and other trading activities to conform to the current period presentation.

(2) The environmental and tax attributes represent environmental attributes and production tax transfer sales not bundled with power and other sales.

(3) Represents realized and unrealized gains or losses from hedging and derivative positions. Volatility and pricing in commodity markets can vary significantly from period to period and impact movements in derivative positions.

(4) Other revenue includes production tax credits related to U.S. wind facilities subject to tax equity financing arrangements, total lease income from long-term contracts that meet the criteria of operating leases and other miscellaneous revenues.

Year ended Dec. 31, 2022	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Revenues from contracts with customers							
Power and other	33	220	462	10	—	—	725
Environmental and tax attributes[1]	1	50	—	—	—	—	51
Revenue from contracts with customers	34	270	462	10	—	—	776
Revenue from derivatives and other trading activities[2]	—	(121)	(821)	243	160	(2)	(541)
Revenue from merchant sales	564	119	1,529	461	—	—	2,673
Other[3]	8	21	39	—	—	—	68
Total revenue	606	289	1,209	714	160	(2)	2,976
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	1	50	—	12	—	—	63
Over time	33	220	462	(2)	—	—	713
Total revenue from contracts with customers	34	270	462	10	—	—	776

(1) The environmental and tax attributes represent environmental attributes and production tax transfer sales not bundled with power and other sales.

(2) Represents realized and unrea ized gains or losses from hedging and derivative positions. Volatility and pricing in commodity markets can vary significantly from period to period and impact movements in derivative positions.

(3) Other revenue includes production tax credits related to U.S. wind facilities subject to tax equity financing arrangements, total lease income from long-term contracts that meet the criteria of operating leases and other miscellaneous revenues.

B. Performance Obligations

The performance obligations in the Company's contracts with its customers include the provision of electricity and steam capacity; the delivery of electricity, thermal energy and environmental attributes; the provision of operation and maintenance services and water management services; and the supply of byproducts from coal generation.

The aggregate amount of transaction prices allocated to remaining performance obligations (contract revenues that have not yet been recognized) as at Dec. 31, 2024, is approximately $2,336 million, with approximately $455 million expected to be recognized during the period 2025-2027; $391 million for the period of 2028-2030; $668 million for the period of 2031-2035; and $822 million for 2036 and thereafter.

These amounts exclude revenues related to contracts that qualify for the invoice practical expedient and future revenues that are related to constrained variable consideration. In many of the Company's contracts, elements of the transaction price are considered constrained, such as for variable revenues dependent upon future production volumes that are driven by customer or market demand or market prices that are subject to factors outside the Company's influence. As a result, the amounts of future revenues disclosed above represent only a portion of future revenues that are expected to be realized by the Company from its contractual portfolio.

Contract liabilities of $36 million as at Dec. 31, 2024 represent the consideration received from customers in advance of satisfying the related performance obligation by supplying the related goods. Revenue is recognized when the performance obligation is satisfied. $6 million of contract liabilities were acquired from Heartland (refer to Note 4).

6. Expenses by Nature

Fuel, Purchased Power and Operations, Maintenance and Administration (OM&A)

Fuel and purchased power and OM&A expenses classified by nature are as follows:

	2024		2023[1]		2022	
Year ended Dec. 31	Fuel and purchased power	OM&A	Fuel and purchased power	OM&A	Fuel and purchased power	OM&A
Gas fuel costs	**369**	**—**	384	—	578	—
Coal fuel costs	**123**	**—**	177	—	146	—
Royalty, land lease, other direct costs	**28**	**—**	25	—	25	—
Purchased power	**419**	**—**	474	—	514	—
Salaries and benefits	**—**	**296**	—	254	—	263
Other operating expenses[1]	**—**	**359**	—	285	—	258
Total	**939**	**655**	1,060	539	1,263	521

(1) Included in OM&A costs for 2023 was $14 million related to the write-down of parts and material inventory related to our natural-gas-fired facilities.

Brazeau — Spinning Reserve Self-Report

In 2022 a provision of $20 million was initially recognized in revenue reflecting a potential disgorgement of revenue and $2 million for potential penalties and fines. The final assessment contained no disgorgement of revenue and penalties of $33 million. This resulted in a reversal of the original disgorgement provision in revenue in the year ended Dec. 31, 2024 and recognition of the full amount of the penalties assessed in OM&A. Refer to Note 37 for details.

Acquisition-related transaction and restructuring costs

During the year ended Dec. 31, 2024, the Company recognized $24 million in acquisition-related transaction and restructuring costs in OM&A costs as part of other operating expenses related to the acquisition of Heartland, mainly comprising severance, legal and consulting fees.

7. Asset Impairment Charges (Reversals)

As part of the Company's monitoring controls, long-range forecasts are prepared for each CGU. The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide criteria to evaluate adverse changes in operations. The Company also considers the relationship between its market capitalization and its book value, among other factors, when reviewing for indicators of impairment. When indicators of impairment are present, the Company estimates a recoverable amount (the higher of value in use or fair value less costs of disposal) for the affected CGUs using discounted cash flow projections. The valuations are subject to measurement uncertainty from assumptions and inputs to the discount rates, power price forecasts, useful lives of the assets (extending to the last planned asset retirement in 2072) and long-range forecasts, which include changes to production, fuel costs, operating costs and capital expenditures. The Company recognized the following asset impairment charges (reversals):

Year ended Dec. 31	2024	2023	2022
Segments:			
Hydro	—	(10)	21
Wind and Solar	—	(4)	43
Corporate	—	—	(2)
Changes in decommissioning and restoration provisions on retired assets[1]	24	(34)	(53)
Project development costs	22	—	—
Asset impairment charges (reversals)	**46**	(48)	9

(1) Changes relate to changes in discount rates and revisions in estimated decommissioning costs on retired assets in 2024, 2023 and 2022. Refer to Note 24 for further details.

During 2024, the Company recognized impairment of project development costs related to projects that are no longer proceeding.

Hydro

During 2023, internal valuations indicated the fair value less costs of disposal for two hydro facilities exceeded the carrying value due to a contract extension and changes in power price assumptions, which favourably impacted estimated future cash flows and resulted in a recoverability test. As a result of the recoverability test, an impairment reversal of $10 million was recognized. The recoverable amounts of $70 million in total were estimated based on fair value less costs of disposal utilizing a discounted cash flow approach and are categorized as a Level III fair value measurement.

During 2022, the Company recorded net impairment charges of $21 million on four hydro facilities as a result of changes in key assumptions, that included significant increases in discount rates, changes in pricing and changes in estimated future cash flows. The total recoverable amounts of $89 million for these four assets was estimated based on fair value less costs of disposal using a discounted cash flow approach and is categorized as a Level III fair value measurement.

Wind and Solar

During 2023, the Company recorded net impairment reversals of $4 million. Internal valuations indicated the fair value less costs of disposal for three wind facilities exceeded the carrying value due to changes in power price assumptions, which favourably impacted estimated future cash flows and resulted in impairment reversals of $17 million. The total recoverable amounts of $540 million was estimated based on fair value less costs of disposal using a discounted cash flow approach and is categorized as a Level III fair value measurement.

Also in 2023, two wind facilities were impaired, primarily due to unfavourable power price assumptions and changes in estimated future cash flows, resulting in a $13 million impairment charge. The recoverable amounts of $130 million for these two assets were estimated based on fair value less costs of disposal using a discounted cash flow approach and are categorized as a Level III fair value measurement.

During 2022, the Company recorded net impairment charges of $43 million on five wind facilities and one solar facility as a result of changes in key assumptions, that included significant increases in discount rates, changes in pricing and changes in estimated future cash flows. The recoverable amounts of $754 million for these six assets were estimated based on fair value less costs of disposal using a discounted cash flow approach and categorized as a Level III fair value measurement.

8. Net Other Operating Income

Net other operating income includes the following:

Year ended Dec. 31	2024	2023	2022
Alberta Off-Coal Agreements	**(40)**	(40)	(40)
Liquidated damages recoverable	**(10)**	(6)	(12)
Other	**(9)**	(1)	(6)
Net other operating income	**(59)**	(47)	(58)

Alberta Off-Coal Agreements (OCA)

The Company receives payments from the Government of Alberta for the cessation of coal-fired emissions on or before Dec. 31, 2030. Under the terms of the agreements, including those acquired in the recent Heartland acquisition, the Company will receive annual cash payments on or before July 31 of approximately $44 million. These payments will continue until the termination of the agreements at the end of 2030. The Company recognizes the off-coal payments evenly throughout the year. Receipt of the payments is subject to certain terms and conditions, including the cessation of all coal-fired emissions on or before Dec. 31, 2030, which has been achieved. The affected plants are not, however, precluded from generating electricity at any time by any other method, after Dec. 31, 2030.

Liquidated Damages Recoverable

The Company receives liquidated damages related to requirements to be met by the contractor on turbine availability guarantees at our Wind sites.

Sundance A Decommissioning

On Dec. 9, 2024, the Company received the decision by the Alberta Utilities Commission related to Sundance A Reclamation awarding TransAlta a reimbursement of $9 million from the Balancing Pool for TransAlta's decommissioning costs for Sundance A, including its proportionate share of the Highvale mine. The amount, included in other for 2024, represents a shortfall of decommissioning costs of Sundance A. Refer to Note 37 for more details.

9. Investments

The change in investments is as follows:

	EMG	Skookumchuck	Tent Mountain	EIP	Ekona	Total
Classification	Equity-accounted	Equity-accounted	Equity-accounted	FVTPL	FVTOCI	
Balance, Dec. 31, 2022	12	105	—	11	1	129
Investment	—	—	10	4	—	14
Equity (loss) income	(4)	8	—	—	—	4
Distributions received	—	(6)	—	—	—	(6)
Changes in foreign exchange rates	—	(3)	—	—	—	(3)
Balance, Dec. 31, 2023	8	104	10	15	1	138
Investment	**—**	**—**	**3**	**5**	**—**	**8**
Equity (loss) income	**(4)**	**10**	**(1)**	**—**	**—**	**5**
Distributions received	**—**	**(5)**	**—**	**—**	**—**	**(5)**
Changes in foreign exchange rates	**2**	**9**	**—**	**—**	**—**	**11**
Net change in fair value recognized in earnings	**—**	**—**	**—**	**2**	**—**	**2**
Balance, Dec. 31, 2024	**6**	**118**	**12**	**22**	**1**	**159**

Equity-accounted Investments

The Company's investments in joint ventures and associates that are accounted for using the equity method consist of its investments in Skookumchuck, EMG International, LLC (EMG) and Tent Mountain Renewable Energy Complex (Tent Mountain).

EMG International, LLC

TransAlta holds a 30 per cent interest in EMG, a wastewater treatment processing company. Earnings are derived from the design and construction of wastewater treatment facilities.

Skookumchuck Wind Project

TransAlta holds a 49 per cent membership interest in SP Skookumchuck Investment, LLC. Skookumchuck is a 136.8 MW wind project located in Lewis and Thurston counties near Centralia in Washington state. The project has a 20-year PPA with Puget Sound Energy.

Tent Mountain Pumped Hydro Development Project

On April 24, 2023, the Company acquired a 50 per cent interest in Tent Mountain, an early-stage 320 MW pumped hydro energy storage development project, located in southwest Alberta, from Evolve Power Ltd., formerly known as Montem Resources Limited. The acquisition included land rights, fixed assets and intellectual property associated with the pumped hydro development project. The Company paid Evolve $8 million on closing and made additional investments of $2 million during the balance of 2023. On Oct. 8, 2024, the Company increased its interest from 50 to 60 per cent by converting an outstanding loan receivable balance into an additional interest in the partnership. Additional contingent payments of up to $17 million may become payable to Evolve based on the achievement of specific development and commercial milestones. The Company and Evolve jointly control Tent Mountain, with the result that the Company accounts for its interest in the joint venture as an investment using the equity method.

Summarized financial information on the results of operations relating to the Company's pro-rata interests in Skookumchuck, EMG and Tent Mountain, is as follows:

Year ended Dec. 31	2024	2023	2022
Results of operations			
Revenues and other operating income	**28**	22	24
Expenses	**(23)**	(18)	(15)
Proportionate share of net earnings	**5**	4	9

Other Investments

Energy Impact Partners

On May 6, 2022, the Company entered into a commitment to invest US$25 million over the next four years in Energy Impact Partners (EIP) Deep Decarbonization Frontier Fund 1 (the Frontier Fund). The investment in the Frontier Fund provides the Company with a portfolio approach to investing in emerging technologies and the opportunity to identify, pilot, commercialize and bring to market emerging technologies that will facilitate the transition to net-zero emissions. The investment is accounted for at FVTPL.

Ekona Power Inc.

On Feb. 1, 2022, the Company made an equity investment of $2 million in Ekona's Class B Preferred Shares. The investment supports the commercialization of Ekona's novel methane pyrolysis technology platform, which is being developed to produce cleaner and lower-cost turquoise hydrogen. The Company has irrevocably elected to measure its investment in Ekona at FVTOCI.

10. Interest Expense

The components of interest expense are as follows:

	2024	2023	2022
Interest on debt	**197**	203	164
Interest on exchangeable debentures (Note 26)	**31**	29	29
Interest on exchangeable preferred shares (Note 26)	**28**	28	28
Capitalized interest (Note 19)	**(16)**	(57)	(16)
Interest on lease liabilities	**10**	9	7
Credit facility fees, bank charges and other interest	**21**	21	27
Tax shield on tax equity financing (Note 25)	**3**	—	(2)
Accretion of provisions (Note 24)	**50**	48	49
Interest expense	**324**	281	286

11. Income Taxes

Consolidated Statements of Earnings

I. Rate Reconciliation

Year ended Dec. 31	2024	2023	2022
Earnings before income taxes	**319**	880	353
Net earnings attributable to non-controlling interests not subject to tax	**(10)**	(80)	(94)
Adjusted earnings before income taxes	**309**	800	259
Statutory Canadian federal and provincial income tax rate (%)	**23.3%**	23.4%	23.4%
Expected income tax expense	**72**	187	61
(Decrease) increase in income taxes resulting from:			
Differences in effective foreign tax rates	**(6)**	9	(1)
Non-deductible expense[1]	**46**	58	130
Non-taxable income	**(10)**	—	—
Taxable capital loss (gain)	**1**	(2)	18
Deferred income tax recovery related to temporary difference on investment in subsidiaries	**(5)**	(3)	(2)
Reversal of unrecognized deferred income tax assets	**(13)**	(178)	(24)
Statutory and other rate differences	**(1)**	1	(3)
Adjustments in respect of deferred income tax of previous years	**(11)**	1	6
Other	**7**	11	7
Income tax expense	**80**	84	192
Effective tax rate (%)	**26%**	11%	74%

(1) This amount is related to current tax adjustments in the U.S. to mitigate cash tax relating to the Base Erosion and Anti-Abuse Tax, Canadian non-deductible penalties, and a tax adjustment relating to dividends on preferred shares, treated as interest for accounting purposes.

Global Minimum Tax Act

In response to the OECD Pillar Two Model rules, Canada enacted the Global Minimum Tax Act (GMTA) on June 19, 2024. The GMTA provides for a minimum tax of 15 per cent to be applied on a jurisdictional basis. The adoption of the GMTA did not have a material impact on the Company's tax expense. IAS 12 contains a mandatory temporary exception to recognizing and disclosing information about deferred taxes related to Pillar Two. The Company has applied this exception.

II. Components of Income Tax Expense

The components of income tax expense are as follows:

Year ended Dec. 31	2024	2023	2022
Current income tax expense	**143**	50	65
Deferred income tax (recovery) expense related to the origination and reversal of temporary differences	**(45)**	215	153
Deferred income tax recovery related to temporary difference on investment in subsidiaries	**(5)**	(3)	(2)
Reversal of unrecognized deferred income tax assets[1]	**(13)**	(178)	(24)
Income tax expense	**80**	84	192
Current income tax expense	**143**	50	65
Deferred income tax (recovery) expense	**(63)**	34	127
Income tax expense	**80**	84	192

(1) During the year ended Dec. 31, 2024, the Company recognized deferred tax assets of $13 million (2023 — $178 million, 2022 — $24 million). The deferred income tax assets mainly relate to the tax benefits associated with tax losses related to the Company's directly owned U.S. operations and other deductible differences. The Company has not recognized $152 million (2023 — $157 million) of deferred tax assets on the basis that it is not probable that sufficient future taxable income would be available to utilize these tax assets.

Consolidated Statements of Changes in Equity

The aggregate current and deferred income tax related to items charged or credited to equity are as follows:

Year ended Dec. 31	2024	2023	2022
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	**53**	27	(112)
Net impact related to hedges of foreign operations	**(4)**	1	(3)
Net impact related to net actuarial gains (losses)	**3**	(1)	12
Transaction costs for the acquisition of TransAlta Renewables	**—**	(2)	—
Income tax expense (recovery) reported in equity	**52**	25	(103)

Consolidated Statements of Financial Position

Significant components of the Company's deferred income tax assets (liabilities) are as follows:

As at Dec. 31	2024	2023[2]
Non-capital losses[1]	**149**	88
Future decommissioning and restoration costs	**184**	140
Property, plant and equipment	**(646)**	(528)
Investment in subsidiaries[2]	**(60)**	(63)
Risk management assets and liabilities, net	**40**	99
Employee future benefits and compensation plans	**52**	50
Foreign exchange differences	**16**	12
Other taxable temporary differences	**(1)**	(6)
Net deferred income tax liabilities, before unrecognized deferred income tax assets	**(266)**	(208)
Unrecognized deferred income tax assets	**(152)**	(157)
Net deferred income tax liabilities	**(418)**	(365)

(1) Non-capital losses expire between 2031 and 2044. Net operating losses from U.S. operations have no expiration.

(2) Classification for the 2023 comparative figures has been conformed to the current period's presentation.

The net deferred income tax liability is presented in the Consolidated Statements of Financial Position as follows:

As at Dec. 31	2024	2023
Deferred income tax assets[1]	**52**	21
Deferred income tax liabilities	**(470)**	(386)
Net deferred income tax liabilities	**(418)**	(365)

(1) The deferred income tax assets presented on the Consolidated Statements of Financial Position are recoverable based on estimated future earnings and tax planning strategies. The assumptions used in the estimate of future earnings are based on the Company's long-range forecasts.

Contingencies

As of Dec. 31, 2024, the Company had recognized a net liability of nil (2023 — nil) related to uncertain tax positions.

12. Non-Controlling Interests

The Company's subsidiaries and operations that have non-controlling interests are as follows:

Subsidiary/Operation	Non-controlling interest owner	Non-controlling interest as at Dec. 31, 2024	Non-controlling interest as at Dec. 31, 2023
TransAlta Cogeneration LP	Canadian Power Holdings Inc.	**49.99%**	49.99%
Kent Hills Wind LP	Natural Forces Technologies Inc.	**17%**	17%
TransAlta Renewables Inc.	Public shareholders	**nil**	nil[(1)]

(1) Non-controlling interest from Jan. 1, 2023 to Oct. 4, 2023 was 39.9%.

TransAlta Cogeneration, LP (TA Cogen) operates a portfolio of cogeneration facilities in Canada and owns 50 per cent of Sheerness, a dual-fuel generating facility.

Kent Hills Wind LP, a subsidiary, owns and operates the 167 MW Kent Hills (1, 2 and 3) wind facilities located in New Brunswick.

TransAlta Renewables Inc. (TransAlta Renewables) was previously a non-wholly owned publicly traded entity that operated a portfolio of gas and renewable power generation facilities and owned economic interests in various other gas and renewable facilities of the Company.

On Oct. 5, 2023, the Company acquired all of the outstanding common shares of TransAlta Renewables not already owned, directly or indirectly, by TransAlta and certain of its affiliates.

Summarized financial information relating to subsidiaries with significant non-controlling interests is as follows:

TA Cogen

Year ended Dec. 31	2024	2023	2022
Revenues	**167**	290	347
Net earnings and total comprehensive income	**9**	121	143
Amounts attributable to the non-controlling interest:			
Net earnings	**9**	80	91
Total comprehensive income	**9**	80	91
Distributions paid to Canadian Power Holdings Inc.	**40**	148	87

As at Dec. 31	2024	2023
Current assets	**47**	43
Long-term assets	**130**	193
Current liabilities	**(48)**	(41)
Long-term liabilities	**(32)**	(34)
Total equity	**(97)**	(161)
Equity attributable to Canadian Power Holdings Inc.	**(46)**	(79)
Non-controlling interest share (per cent)	**49.99**	49.99

Kent Hills Wind LP

Prior to Oct. 5, 2023, financial information related to the 17 per cent non-controlling interest in Kent Hills Wind LP was included in the financial information disclosed in TransAlta Renewables in this note.

Year ended Dec. 31	2024	2023[1]
Revenues	**34**	7
Net earnings and total comprehensive income	**7**	2
Amounts attributable to the non-controlling interest:		
Net earnings and total comprehensive income	**1**	—

(1) This represents financial information from Oct. 5, 2023 to Dec. 31, 2023. The net earnings attributable to non-controlling interest in Kent Hills Wind LP prior to Oct. 5, 2023, is included in the disclosures for TransAlta Renewables.

As at Dec. 31	2024	2023
Current assets	**33**	35
Long-term assets	**463**	481
Current liabilities	**(26)**	(42)
Long-term liabilities	**(174)**	(188)
Total equity	**(296)**	(285)
Equity attributable to non-controlling interests	**(51)**	(48)
Non-controlling interest share (per cent)	**17**	17

TransAlta Renewables

The financial information disclosed below includes the 17 per cent non-controlling interest in Kent Hills Wind LP until Oct. 5, 2023. TransAlta Renewables at Dec. 31, 2024, and Dec. 31, 2023, is a wholly owned subsidiary of the Company. Refer to Note 4 for more details.

Year ended Dec. 31	2023[1]	2022
Revenues	303	560
Net earnings	56	74
Total comprehensive loss	(7)	(67)
Amounts attributable to the non-controlling interests:		
Net earnings	21	20
Total comprehensive loss	(4)	(36)
Distributions paid to non-controlling interests[2]	75	100

(1) Non-controlling interest share before the close of the transaction on Oct. 5, 2023. This represents financial information from Jan. 1, 2023 to Oct. 4, 2023.

(2) Distributions paid in the year ended Dec. 31, 2023 include $25 million of dividends declared in the fourth quarter of 2022.

13. Trade and Other Receivables and Accounts Payable, accrued liabilities and other current liabilities

As at Dec. 31	2024	2023
Trade accounts receivable	**570**	600
Collateral provided (Note 15)	**124**	145
Current portion of finance lease receivables (Note 17)	**30**	19
Current portion of loan receivable (Note 23)	**1**	1
Income taxes receivable	**42**	42
Trade and other receivables	**767**	807

As at Dec. 31	2024	2023
Accounts payable and accrued liabilities	**694**	772
Income taxes payable	**23**	9
Interest payable	**17**	16
Current portion of contract liabilities (Note 5)	**12**	3
Liabilities Held for Sale	**1**	—
Collateral held (Note 15)	**9**	9
Accounts payable, accrued liabilities and other current liabilities	**756**	809

14. Financial Instruments

A. Financial Assets and Liabilities — Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value or amortized cost.

Carrying value as at Dec. 31, 2024	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Other financial assets and liabilities (FVTPL)	Other financial assets (FVOCI)	Total
Financial assets						
Cash and cash equivalents[1]	—	—	337	—	—	337
Restricted cash	—	—	69	—	—	69
Trade and other receivables[2]	—	—	725	—	—	725
Long-term portion of finance lease receivables	—	—	305	—	—	305
Long-term portion of loan receivable[3]	—	—	24	—	—	24
Other investments[4]	—	—	—	22	1	23
Risk management assets						
Current	45	273	—	—	—	318
Long-term	—	93	—	—	—	93
Financial liabilities						
Bank overdraft	—	—	1	—	—	1
Accounts payable, accrued liabilities and other current liabilities[5]	—	—	720	—	—	720
Contingent consideration	—	—	—	81	—	81
Dividends payable	—	—	49	—	—	49
Risk management liabilities						
Current	—	277	—	—	—	277
Long-term	—	305	—	—	—	305
Credit facilities, long-term debt and lease liabilities[6]	—	—	3,808	—	—	3,808
Exchangeable securities	—	—	750	—	—	750

(1) Includes cash equivalents of nil.

(2) Excludes income taxes receivable.

(3) Included in other assets. Refer to Note 23.

(4) Included in investments. Refer to Note 9.

(5) Excludes the current portion of contract liabilities, current income taxes payable and liabilities held for sale.

(6) Includes current portion.

Carrying value as at Dec. 31, 2023	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Other financial assets (FVTPL)	Other financial assets (FVTOCI)	Total
Financial assets						
Cash and cash equivalents[1]	—	—	348	—	—	348
Restricted cash	—	—	69	—	—	69
Trade and other receivables[2]	—	—	765	—	—	765
Long-term portion of finance lease receivables	—	—	171	—	—	171
Long-term portion of loan receivable[3]	—	—	25	—	—	25
Other investments[4]	—	—	—	15	1	16
Risk management assets						
Current	—	151	—	—	—	151
Long-term	—	52	—	—	—	52
Financial liabilities						
Bank overdraft	—	—	3	—	—	3
Accounts payable, accrued liabilities and other current liabilities[5]	—	—	797	—	—	797
Dividends payable	—	—	49	—	—	49
Risk management liabilities						
Current	125	189	—	—	—	314
Long-term	80	194	—	—	—	274
Credit facilities, long-term debt and lease liabilities[6]	—	—	3,466	—	—	3,466
Exchangeable securities	—	—	744	—	—	744

(1) Includes cash equivalents of nil.

(2) Excludes income taxes receivable.

(3) Included in other assets. Refer to Note 23.

(4) Included in investments. Refer to Note 9.

(5) Excludes the current portion of contract liabilities, current income taxes payable and liabilities held for sale.

(6) Includes current portion.

B. Fair Value of Financial Instruments

The fair value of a financial instrument is the price that would be received when selling the asset or paid to transfer the associated liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by observing quoted prices for the instrument in active markets to which the Company has access. In the absence of an active market, the Company determines fair values based on valuation models or by reference to other similar products in active markets. Fair values determined using valuation models require the use of assumptions. In determining those assumptions, the Company looks primarily to external readily observable market inputs. However, if these are not available, the Company uses inputs that are not based on observable market data.

I. Level I, II and III Fair Value Measurements

The Level I, II and III classifications in the fair value hierarchy used by the Company are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value. The Level III classification is the lowest level classification in the fair value hierarchy.

a. Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Company has the ability to access at the measurement date. In determining Level I fair values, the Company uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

b. Level II

Fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis, credit valuation and location differentials.

The Company's commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and interpolation formulas, where the inputs are readily observable.

In determining Level II fair values of other risk management assets and liabilities, the Company uses observable inputs other than unadjusted quoted prices that are observable for the asset or liability, such as interest rate yield curves and currency rates. For certain financial instruments where insufficient trading volume or lack of recent trades exists, the Company relies on similar interest or currency rate inputs and other third-party information such as credit spreads.

c. Level III

Fair values are determined using inputs for the assets or liabilities that are not readily observable.

The Company may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques such as mark-to-forecast and mark-to-model. For mark-to-model valuations, derivative pricing models, regression-based models and scenario analysis simulation models may be employed. The model inputs may be based on historical data such as unit availability, transmission congestion, demand profiles for individual non-standard deals and structured products and/or volatility and correlations between products derived from historical price relationships. For assets and liabilities that are recognized at fair value on a recurring basis, the Company determines whether transfers have occurred between levels in the hierarchy by re-assessing categorization (based on the lowest level input that is significant to the fair value measurement as a whole) at the end of each reporting period.

The Company also has various commodity contracts with terms that extend beyond a liquid trading period. As forward market prices are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III.

II. Commodity Risk Management Assets and Liabilities

Commodity risk management assets and liabilities include risk management assets and liabilities that are used in the energy marketing and generation segments in relation to trading activities and certain contracting activities. To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within earnings of these businesses.

Commodity risk management assets and liabilities classified by fair value levels as at Dec. 31, 2024, are as follows: Level I – $12 million net liability (Dec. 31, 2023 – $13 million net liability), Level II – $2 million net liability (Dec. 31, 2023 – $244 million net liability) and Level III – $153 million net liability (Dec. 31, 2023 – $147 million net liability).

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2024, are primarily attributable to contract settlements and volatility in market prices across multiple markets on both existing contracts and new contracts.

The following table summarizes the key factors impacting the fair value of the Level III commodity risk management assets and liabilities by classification during the years ended Dec. 31, 2024 and 2023, respectively:

	Year ended Dec. 31, 2024			Year ended Dec. 31, 2023		
	Hedge	Non-hedge	Total	Hedge	Non-hedge	Total
Opening balance	—	(147)	(147)	(347)	(435)	(782)
Changes attributable to:						
New contracts added[1]	—	3	3	—	—	—
Market price changes on existing contracts	—	(49)	(49)	(123)	(6)	(129)
Market price changes on new contracts	—	27	27	—	18	18
Contracts settled	—	23	23	256	269	525
Change in foreign exchange rates	—	(10)	(10)	9	7	16
Transfers out of Level III[2]	—	—	—	205	—	205
Net risk management assets (liabilities) at end of year	—	(153)	(153)	—	(147)	(147)
Additional Level III information:						
Losses recognized in other comprehensive loss	—	—	—	(114)	—	(114)
Total (losses) gains included in earnings before income taxes	—	(32)	(32)	(256)	19	(237)
Unrealized (losses) gains included in earnings before income taxes relating to net assets (liabilities) held at year end	—	(9)	(9)	—	288	288

(1) New contracts added in 2024 represent the contracts acquired from Heartland.

(2) The Company has a long-term fixed price power sale contract in the U.S. for de ivery of power. The fair value was transferred out of Level III to Level II as at Dec. 31, 2023 as the forward price curve was based on observable market prices for the remaining duration of the contract.

The Company has a Commodity Exposure Management Policy that governs both the commodity transactions undertaken in its proprietary trading business and those undertaken to manage commodity price exposures in its generation business. This Policy defines and specifies the controls and management responsibilities associated with commodity trading activities, as well as the nature and frequency of required reporting of such activities.

The Company's risk management department determines methodologies and procedures regarding commodity risk management Level III fair value measurements. Level III fair values are primarily calculated within the Company's energy trading risk management processes. These calculations are based on underlying contractual data as well as observable and non-observable inputs. Development of non-observable inputs requires the use of judgment. To ensure reasonability, the Level III fair value measurements are reviewed and validated by the risk management and finance departments. Review occurs formally on a quarterly basis or more frequently if daily review and monitoring procedures identify unexpected changes to fair value or changes to key parameters.

As at Dec. 31, 2024, the total Level III risk management asset balance was $110 million (Dec. 31, 2023 – $56 million) and the Level III risk management liability balance was $263 million (Dec. 31, 2023 – $203 million). The net risk management liabilities increased mainly due to market price changes offset by settled contracts. The information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities are outlined in the following table. These include the effects on fair value of discounting, liquidity and credit value adjustments; however, the potential offsetting effects of Level II positions are not considered. Sensitivity ranges for the base fair values are determined using reasonably possible alternative assumptions for the key unobservable inputs, which may include forward commodity prices, volatility in commodity prices and correlations, delivery volumes, escalation rates and cost of supply.

As at		Dec. 31, 2024		
Description	**Valuation technique**	**Unobservable input**	**Reasonably possible change**	**Sensitivity[1]**
Coal transportation – U.S.	Numerical derivative valuation	Volatility	80% to 120%	+1
		Rail rate escalation	0% to 10%	-1
Long-term wind energy sale — Eastern U.S.	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease or increase of US$6	+42
		Illiquid future REC[2] prices (per unit)	Price decrease of US$12 or increase of US$8	
		Wind discounts	0% decrease or 6% increase	-30
Long-term wind energy sale — Canada	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of $57 or increase of $10	+53
		Wind discounts	15% decrease or 5% increase	-17
Long-term wind energy sale — Central U.S.	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$4 or increase of US$3	+84
		Wind discounts	2% decrease or 2% increase	-77

(1) Sensitivity represents the total increase or decrease in recognized fair value that could arise from the use of the reasonably possible changes of all unobservable inputs.

(2) Renewable energy credits

As at		Dec. 31, 2023		
Description	**Valuation technique**	**Unobservable input**	**Reasonably possible change**	**Sensitivity[1]**
Coal transportation — U.S.	Numerical derivative valuation	Volatility	80% to 120%	+6
		Rail rate escalation	0% to 10%	-4
Long-term wind energy sale — Eastern U.S.	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease or increase of US$6	+24
		Illiquid future REC prices (per unit)	Price decrease of US$12 or increase of US$8	
		Wind discounts	0% decrease or 9% increase	-28
Long-term wind energy sale — Canada	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of $81 or increase of $5	+65
		Wind discounts	16% decrease or 5% increase	-23
Long-term wind energy sale — Central U.S.	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$1 or increase of US$2	+81
		Wind discounts	5% decrease or 2% increase	-36

(1) Sensitivity represents the total increase or decrease in recognized fair value that would arise from the use of the reasonably possible changes of all unobservable inputs.

a. Coal Transportation – U.S.

The Company has a coal rail transport agreement that includes an upside sharing mechanism until Dec. 31, 2025. Option pricing techniques have been utilized to value the obligation associated with this component of the agreement.

The key unobservable inputs used in the valuation include option volatility and rail rate escalation. Option volatility and rail rate escalation ranges have been determined based on historical data and professional judgment.

b. Long-Term Wind Energy Sale – Eastern U.S.

The Company is party to a long-term contract for differences (CFD) for the offtake of 100 per cent of the

generation from its 90 MW Big Level wind facility. The CFD, together with the sale of electricity generated into the PJM Interconnection at the prevailing real-time energy market price, achieve the fixed contract price per MWh on proxy generation. Under the CFD, if the market price is lower than the fixed contract price, the customer pays the Company the difference and if the market price is higher than the fixed contract price, the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The contract matures in December 2034. The contract is accounted for as a derivative with changes in fair value presented in revenue.

The key unobservable inputs used in the valuation of the contract are expected proxy generation volumes and non-liquid forward prices for power, RECs and wind discounts.

c. Long-Term Wind Energy Sale – Canada

The Company is party to two Virtual Power Purchase Agreements (VPPAs) for the offtake of 100 per cent of the generation from its 130 MW Garden Plain wind facility. The VPPAs, together with the sale of electricity generated into the Alberta power market at the pool price, achieve the fixed contract prices per MWh. Under the VPPAs, if the pool price is lower than the fixed contract price, the customer pays the Company the difference and if the pool price is higher than the fixed contract price, the Company refunds the difference to the customer. Customers are also entitled to the physical delivery of environmental attributes. Both VPPAs commenced on commercial operation of the facility in August 2023, and extend for a weighted average period of approximately 17 years.

The energy components of these contracts are accounted for as derivatives, with changes in fair value presented in revenue.

The key unobservable inputs used in the valuations of the contracts are the non-liquid forward prices for power and monthly wind discounts.

d. Long-Term Wind Energy Sale – Central U.S.

The Company is party to two long-term VPPAs for the offtake of 100 per cent of the generation from its 302 MW White Rock East and White Rock West wind power facilities. The VPPAs, together with the sale of electricity generated into the U.S. Southwest Power Pool (SPP) market at the relevant price nodes, achieve the fixed contract prices per MWh. Under the VPPAs, if the SPP pricing is lower than the fixed contract price the customer pays the Company the difference, and if the SPP pricing is higher than the fixed contract price, the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The VPPAs commenced on commercial operation of the facilities in the first quarter of 2024.

The Company is also party to a VPPA for the offtake of 100 per cent of the generation from its 202 MW Horizon Hill wind power project. The VPPA, together with the sale of electricity generated into the SPP market at the relevant price node, achieve the fixed contract price per MWh. Under the VPPA, if the SPP pricing is lower than the fixed contract price, the customer pays the Company the difference and if the SPP pricing is higher than the fixed contract price, the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The VPPA commenced on commercial operation of the facility in the second quarter of 2024.

The energy components of these contracts are accounted for as derivatives, with changes in fair value presented in revenue.

The key unobservable inputs used in the valuation of the contracts are the non-liquid forward prices for power and wind discounts.

III. Other Risk Management Assets and Liabilities

Other risk management assets and liabilities primarily include risk management assets and liabilities that are used to manage exposures on non-energy marketing transactions such as interest rates, the net investment in foreign operations and other foreign currency risks. Hedge accounting is not always applied.

Other risk management assets and liabilities with a total net liability fair value of $4 million as at Dec. 31, 2024 (Dec. 31, 2023 – $19 million net asset) are classified as Level II fair value measurements. The changes in other net risk management assets and liabilities during the year ended Dec. 31, 2024, are attributable to contracts acquired through the Heartland acquisition (Note 4), offset by unfavorable market price changes on existing contracts, unfavorable foreign exchange rates on new contracts entered into during 2024, and contracts settled during 2024.

IV. Other Financial Assets and Liabilities

The fair value of financial assets and liabilities measured at other than fair value is as follows:

	Fair value[1]				Total carrying value[1]
	Level I	Level II	Level III	Total	
Exchangeable securities — Dec. 31, 2024	—	739	—	739	750
Long-term debt — Dec. 31, 2024	—	3,447	—	3,447	3,657
Loan receivable — Dec. 31, 2024	—	25	—	25	25
Exchangeable securities — Dec. 31, 2023	—	718	—	718	744
Long-term debt — Long-term debt — Dec. 31, 2023	—	3,104	—	3,104	3,323
Loan receivable — Dec. 31, 2023	—	26	—	26	26

(1) Includes current portion.

The fair values of the Company's debentures, senior notes and exchangeable securities are determined using prices observed in secondary markets. Non-recourse and other long-term debt fair values are determined by calculating an implied price based on a current assessment of the yield to maturity.

The carrying amount of other short-term financial assets and liabilities (cash and cash equivalents, restricted cash, trade accounts receivable, collateral provided, bank overdraft, accounts payable and accrued liabilities, collateral held and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the finance lease receivables approximate the carrying amounts as the amounts receivable represent cash flows from repayments of principal and interest.

C. Inception Gains and Losses

The majority of derivatives traded by the Company are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this Note 14 above for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the transaction price) and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Consolidated Statements of Financial Position in risk management assets or liabilities and is recognized in net earnings (loss) over the term of the related contract.

The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net earnings (loss) and a reconciliation of changes is as follows:

As at Dec. 31	2024	2023	2022
Unamortized net gain (loss) at beginning of year	**3**	(213)	(131)
New inception gains (losses)[1]	**31**	47	(37)
Change resulting from amended contract[2]	**—**	190	—
Change in foreign exchange rates	**(3)**	6	(10)
Amortization recorded in net earnings during the year	**(20)**	(27)	(35)
Unamortized net gain (loss) at end of year	**11**	3	(213)

(1) During 2024 and 2023, the Company entered into long-term fixed price power sale contracts with certain of its U.S. customers that resulted in new inception losses due to the difference between the fixed PPA price and future estimated market prices. There are other key factors, such as project economics and incentives, that influence the long-term power price for renewable projects outside of the power price curve, which is not liquid for the majority of the duration of the PPA.

(2) During 2023, the Company entered into certain contract amendments related to the Horizon Hill and White Rock wind projects. These amendments were mainly specific to obtaining price increases over the contract term. Accordingly, certain inception loss calibration adjustments were recognized within the risk management liability.

15. Risk Management Activities

A. Risk Management Strategy

The Company is exposed to market risk from changes in commodity prices, foreign exchange rates, interest rates, credit risk and liquidity risk. These risks affect the Company's earnings and the value of associated financial instruments that the Company holds. In certain cases, the Company seeks to minimize the effects of these risks by using derivatives to hedge its risk exposures. The Company's risk management strategy, policies and controls are designed to ensure that the risks it assumes comply with the Company's internal objectives and risk tolerance.

The Company has two primary streams of risk management activities: (i) financial exposure management; and (ii) commodity exposure management. Within these activities, risks identified for management include commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk.

The Company seeks to minimize the effects of commodity risk, interest rate risk and foreign currency risk by using derivative financial instruments to hedge risk exposures. Of these derivatives, the Company may apply hedge accounting to those hedging commodity price risk, interest rate risk and foreign currency risk.

The use of financial derivatives is governed by the Company's policies approved by the Board, which provide written principles on commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk, as well as the use of financial derivatives and non-derivative financial instruments.

Liquidity risk, credit risk and equity price risk are managed through means other than derivatives or hedge accounting.

The Company enters into various derivative transactions as well as other contracting activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, the related assets and liabilities are classified as derivatives at fair value through profit and loss. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in net earnings in the period the change occurs.

The Company designates certain derivatives as hedging instruments to hedge commodity price risk, foreign currency exchange risk in cash flow hedges and hedges of net investments in foreign operations. Hedges of foreign exchange risk on firm commitments are accounted for as cash flow hedges.

At the inception of the hedge relationship, the Company documents the relationship between the hedging instrument and the hedged item, along with its risk management objectives and its strategy for undertaking various hedge transactions. At the inception of the hedge and on an ongoing basis, the Company also documents whether the hedging instrument is effective in offsetting changes in fair values or cash flows of the hedged item attributable to the hedged risk, which is when the hedging relationships meet all of the following hedge effectiveness requirements:

- There is an economic relationship between the hedged item and the hedging instrument;
- The effect of credit risk does not dominate the value changes that result from that economic relationship; and
- The hedge ratio of the hedging relationship is the same as that resulting from the quantity of the hedged item that the Company actually hedges and the quantity of the hedging instrument that the entity actually uses to hedge that quantity of hedged item.

If a hedging relationship ceases to meet the hedge effectiveness requirement relating to the hedge ratio, but the risk management objective for that designated hedging relationship remains the same, the Company adjusts the hedge ratio of the hedging relationship so that it continues to meet the qualifying criteria.

B. Net Risk Management Assets and Liabilities

Aggregate net risk management assets (liabilities) are as follows:

As at Dec. 31, 2024

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	45	8	53
Long-term	—	(220)	(220)
Net commodity risk management assets (liabilities)	45	(212)	(167)
Other			
Current	—	(12)	(12)
Long-term	—	8	8
Net other risk management liabilities	—	(4)	(4)
Total net risk management assets (liabilities)	45	(216)	(171)

As at Dec. 31, 2023

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	(125)	(53)	(178)
Long-term	(80)	(146)	(226)
Net commodity risk management liabilities	(205)	(199)	(404)
Other			
Current	—	15	15
Long-term	—	4	4
Net other risk management liabilities	—	19	19
Total net risk management liabilities	(205)	(180)	(385)

Netting Arrangements

Information about the Company's financial assets and liabilities that are subject to enforceable master netting arrangements or similar agreements is as follows:

As at Dec. 31, 2024	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Net amounts included on the statement of financial position	Master netting arrangements[1]	Net amount
Current risk management assets	**686**	**(421)**	**265**	**(18)**	**247**
Long-term risk management assets	**153**	**(59)**	**94**	**(1)**	**93**
Current risk management liabilities	**(662)**	**421**	**(241)**	**18**	**(223)**
Long-term risk management liabilities	**(128)**	**59**	**(69)**	**1**	**(68)**
Trade and other receivables[2]	**1,519**	**(1,273)**	**246**	**(7)**	**239**
Accounts payable and accrued liabilities[2]	**(1,470)**	**1,273**	**(197)**	**7**	**(190)**

As at Dec. 31, 2023	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Net amounts included on the statement of financial position	Master netting arrangements[1]	Net amount
Current risk management assets	528	(355)	173	(7)	166
Long-term risk management assets	161	(91)	70	(2)	68
Current risk management liabilities	(504)	355	(149)	7	(142)
Long-term risk management liabilities	(145)	91	(54)	2	(52)
Trade and other receivables[2]	789	(646)	143	(11)	132
Accounts payable and accrued liabilities[2]	(760)	646	(114)	11	(103)

(1) Amounts not set off in the Consolidated Statements of Financial Position.

(2) The trade and other receivables and accounts payable and accrued liabilities include amounts related to collateral provided and held. Refer to Note 15(F) below for further details.

C. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

a. Commodity Price Risk Management

The Company has exposure to movements in certain commodity prices in both its electricity generation and proprietary trading businesses, including the market price of electricity and fuels used to produce electricity. Most of the Company's electricity generation and related fuel supply contracts are considered to be contracts for delivery or receipt of a non-financial item in accordance with the Company's expected own use requirements and are not considered to be financial instruments. As such, the discussion related to commodity price risk is limited to the Company's proprietary trading business, VPPAs and other long-term contracts that are derivatives and commodity derivatives used in hedging relationships associated with the Company's electricity generating activities.

To mitigate the risk of adverse commodity price changes, the Company uses three tools:

- A framework of risk controls;
- A predefined hedging plan, including fixed price financial power swaps and long-term physical power sale contracts to hedge commodity price for electricity generation; and
- A committee dedicated to overseeing the risk and compliance program in trading and ensuring the existence of appropriate controls, processes, systems and procedures to monitor adherence to the program.

The Company has executed commodity price hedges for its Centralia thermal facility, including a long-term physical power sale contract, and may, at times, execute hedges for its electricity price exposure in Alberta using fixed price financial swaps or other similar instruments. Both hedging strategies fall under the Company's risk management strategy used to hedge commodity price risk.

Market risk exposures are measured using Value at Risk (VaR) supplemented by sensitivity analysis. There has been no change to the Company's exposure to market risks or the manner in which these risks are managed or measured. Position sizes and trade strategies were adjusted to remain within the Company's risk framework.

i. Commodity Price Risk Management – Proprietary Trading

The Company's Energy Marketing segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue and gain market information.

In compliance with the Company's Commodity Exposure Management Policy, proprietary trading activities are subject to limits and controls, including VaR limits. The Board approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions.

A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. VaR is used to determine the potential change in value of the Company's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance/covariance approach. This measure has inherent limitations. VaR relies on historical data, assuming that past price movements will reflect future market risks. Consequently, it may only be meaningful under normal market conditions and does not account for extreme market events. In addition, the use of a three-day measurement period implies that positions can be unwound or hedged within three days, although this may not be possible if the market becomes illiquid.

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Dec. 31, 2024, associated with the Company's proprietary trading activities was $3 million (2023 — $4 million, 2022 — $4 million).

ii. Commodity Price Risk – Generation

The generation segments utilize various commodity contracts to manage the commodity price risk associated with electricity generation, fuel purchases, emissions and byproducts, as considered appropriate. A Commodity Exposure Management Policy is prepared and approved annually, which outlines the intended hedging strategies associated with the Company's generation assets and related commodity price risks. Controls also include restrictions on authorized instruments, management reviews on individual portfolios and approval of asset transactions that could add potential volatility to the Company's reported net earnings.

VaR at Dec. 31, 2024, associated with the Company's commodity derivative instruments used in generation hedging activities was $8 million (2023 — $23 million, 2022 — $97 million). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Dec. 31, 2024, associated with these transactions was $13 million (2023 — $16 million, 2022 — $45 million).

For the market risk related to long-term power sale and long-term wind energy sales contracts, refer to the Level III measurements table and the related unobservable inputs and sensitivities in Note 14(B)(II).

iii. Commodity Price Risk Management – Hedges

At Dec. 31, 2024, the Company had no outstanding commodity derivative instruments designated as hedging instruments, except for the long-term power sale - U.S. contract.

iv. Commodity Price Risk Management – Non-Hedges

The Company's outstanding commodity derivative instruments not designated as hedging instruments are as follows:

As at Dec. 31	2024		2023	
Type (thousands)	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity (MWh)	**47,593**	**8,416**	54,043	12,628
Natural gas (GJ)	**2,122**	**79,194**	50,949	209,348
Transmission (MWh)	**—**	**292**	—	856
Emissions (MWh)	**167**	**370**	212	804
Emissions (tonnes)	**1,850**	**150**	4,450	5,125
Coal (tonnes)	**—**	**1,728**	—	5,172

b. Interest Rate Risk Management

Changes in interest rates can impact the Company's borrowing costs and cost of capital. Changes in the cost of capital could affect the feasibility of new growth initiatives. Interest rate risk also arises as the fair value of future cash flows from a financial instrument fluctuates due to changes in market interest rates.

The Company's syndicated credit facility, Term Facility, Heartland Term Facility and the Poplar Creek non-recourse bond are subject to floating interest rates, which represent 23 per cent of the Company's total long-term debt as at Dec. 31, 2024 (2023 — 14 per cent). Interest rate risk is managed with the use of derivatives.

In 2024, the Company had interest rate swap agreements in place with a notional amount of $190 million, which are not designated as hedges, whereby the Company receives a variable rate of interest equal to the three-month CORRA rate plus a 0.321 per cent premium, and pays interest at a fixed rate equal to a weighted average of 1.64 per cent on the notional amount.

The term and credit facilities with $545 million outstanding (2023 — $400 million) reference Canadian Overnight Repo Rate Average (CORRA) for Canadian-dollar drawings, which replaced the Canadian Dollar Offered Rate (CDOR) on July 1, 2024 as part of Interbank Offered Rate reform. The Poplar Creek non-recourse bond with a face value as at Dec. 31, 2024 of $76 million (2023 — $86 million) pays interest based upon the three-month CORRA.

c. Currency Rate Risk

The Company has exposure to various currencies, such as the U.S. dollar and the Australian dollar, as a result of investments and operations in foreign jurisdictions, the net earnings from those operations and the acquisition of equipment and services from foreign suppliers.

The Company may enter into the following hedging strategies to mitigate currency rate risk, including:

- Foreign exchange forward contracts to mitigate adverse changes in foreign exchange rates on project-related expenditures and distributions received in foreign currencies;
- Foreign exchange forward contracts and cross-currency swaps to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge; and
- Designating foreign currency debt as a hedge of the net investment in foreign operations to mitigate the risk due to fluctuating exchange rates related to certain foreign subsidiaries.

The Company's target is to hedge a minimum of 60 per cent of our forecasted foreign operating cash flows over a four-year period. The U.S. exposure is managed with a combination of interest expense on our U.S. dollar denominated debt and forward foreign exchange contracts and the Australian exposure is managed with a combination of interest expense on Australian-dollar denominated debt and forward foreign exchange contracts.

i. Net Investment Hedges

When designating foreign currency debt as a hedge of the Company's net investment in foreign subsidiaries, the Company has determined that the hedge is effective if the foreign currency of the net investment is the same as the currency of the hedge and therefore an economic relationship is present.

The Company's hedges of its net investment in foreign operations were comprised of U.S.-dollar-denominated long-term debt with a face value of US$300 million (2023 — US$370 million).

ii. Non-Hedges

The Company also uses foreign currency contracts to manage its expected foreign operating cash flows and foreign exchange forward contracts to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge. Hedge accounting is not applied to these foreign currency contracts.

As at Dec. 31	2024			2023			
Notional amount sold	Notional amount purchased	Fair value (liability) asset	Maturity	Notional amount sold	Notional amount purchased	Fair value (liability) asset	Maturity
Foreign exchange forward contracts – foreign-denominated receipts/expenditures							
AUD14	**CAD10**	**(1)**	**2025-2028**	AUD125	CAD113	(1)	2024-2027
USD419	**CAD585**	**(13)**	**2025-2028**	USD828	CAD1,113	19	2024-2027
USD101	**AUD153**	**(9)**	**2025**	USD100	AUD152	5	2024
Foreign exchange forward contracts – foreign-denominated debt							
CAD192	**USD140**	**8**	**2025**	CAD190	USD140	(4)	2024

iii. Impacts of Currency Rate Risk

The possible effect on net earnings and OCI, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the Company's functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average three cents (2023 — three cents, 2022 — three cents) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	2024		2023		2022	
Currency	Net earnings decrease[1]	OCI gain[1][2]	Net earnings decrease[1]	OCI gain[1][2]	Net earnings decrease[1]	OCI gain[1][2]
USD	**(17)**	**—**	(11)	—	(12)	—
AUD	**(3)**	**—**	(3)	—	(2)	—
Total	**(20)**	**—**	(14)	—	(14)	—

(1) These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect.

(2) The foreign exchange impact related to financial instruments designated as hedging instruments in net investment hedges has been excluded.

II. Credit Risk

Credit risk is the risk that customers or counterparties will cause a financial loss for the Company by failing to discharge their obligations and the risk to the Company associated with changes in creditworthiness of entities with which commercial exposures exist. The Company actively manages its exposure to credit risk by assessing the ability of counterparties to fulfil their obligations under the related contracts before entering into such contracts. The Company makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees, cash collateral, third-party credit insurance and/or letters of credit to support the ultimate collection of these receivables. For commodity trading and origination, the Company sets strict credit limits for each counterparty and monitors exposures on a daily basis. TransAlta uses standard agreements that allow for the netting of exposures and often include margining provisions. If credit limits are exceeded, TransAlta will request collateral from the counterparty or halt trading activities with the counterparty.

The Company uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. The following table outlines the Company's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at Dec. 31, 2024:

	Investment grade (per cent)	Non-investment grade (per cent)	Total (per cent)	Total amount
Trade and other receivables[1]	87	13	100	**767**
Long-term finance lease receivable	100	—	100	**305**
Risk management assets[1]	58	42	100	**411**
Loans receivable[2]	—	100	100	**25**
Total				**1,508**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.

(2) Includes $25 million loans receivable included within other assets with counterparties that have no external credit rating.

An impairment analysis is performed at each reporting date using a provision matrix to measure expected credit losses. The provision rates are based on segment historical rates of default of trade receivables as well as incorporating forward-looking credit ratings and forecasted default rates. In addition to the calculation of expected credit losses, TransAlta monitors key forward-looking information as potential indicators that historical bad debt percentages, forward-looking S&P credit ratings and forecasted default rates would no longer be representative of future expected credit losses. The calculation reflects the probability-weighted outcome, the time value of money and reasonable and supportable information that is available at the reporting date about past events, current conditions and forecasts of future economic conditions.

TransAlta evaluates the concentration of risk with respect to trade receivables as low, as its customers are located in several jurisdictions and industries. The Company did not have material expected credit losses as at Dec. 31, 2024.

The Company's maximum exposure to credit risk at Dec. 31, 2024, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of receivables and risk management assets as per the Consolidated Statements of Financial Position. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trading, net of any collateral held, at Dec. 31, 2024, was $77 million (Dec. 31, 2023 – $23 million).

III. Liquidity Risk

Liquidity risk relates to the Company's ability to access capital to be used for capital projects, debt refinancing, proprietary trading activities, commodity hedging and general corporate purposes. As at Dec. 31, 2024, TransAlta maintains an investment grade rating from one credit rating agency and one notch below investment grade ratings from two credit rating agencies. Between 2025 and 2027, the Company has $400 million of debt maturing, and an additional $666 million of scheduled non-recourse debt and tax equity principal payments.

Collateral is posted based on negotiated terms with counterparties, which can include the Company's senior unsecured credit rating as determined by certain major credit rating agencies. Some of the Company's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs.

TransAlta manages liquidity risk by monitoring liquidity on trading positions; preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital; reporting liquidity risk exposure for proprietary trading activities on a regular basis to the Risk Management Committee, senior management and the Audit, Finance and Risk Committee (on behalf of the Board); and maintaining sufficient undrawn committed credit lines to support potential liquidity requirements. The Company does not use derivatives or hedge accounting to manage liquidity risk. A maturity analysis of the Company's financial liabilities is as follows:

	2025	2026	2027	2028	2029	2030 and thereafter	Total
Bank overdraft	1	—	—	—	—	—	1
Accounts payable, accrued liabilities and other current liabilities	756	—	—	—	—	—	756
Long-term debt[1]							
Credit facilities[1]	400	—	—	145	—	—	545
Debentures	—	—	—	—	110	141	251
Senior notes	—	—	—	—	575	431	1,006
Non-recourse – Hydro	—	—	—	—	—	39	39
Non-recourse – Wind & Solar	69	68	69	74	42	248	570
Non-recourse and other – Gas	58	61	65	66	74	628	952
Non-recourse Heartland term facility	24	24	176	—	—	—	224
Tax equity financing	15	16	21	24	23	6	105
Exchangeable securities[2]	—	—	—	—	—	750	750
Commodity risk management (assets) liabilities[3]	(55)	14	13	12	6	177	167
Other risk management (assets) liabilities	11	(1)	—	(1)	(1)	(4)	4
Lease liabilities	4	5	5	5	5	127	151
Interest on long-term debt and lease liabilities[4]	205	178	169	151	136	649	1,488
Interest on exchangeable securities[2][4]	53	53	53	52	12	—	223
Dividends payable	49	—	—	—	—	—	49
Total	**1,590**	**418**	**571**	**528**	**982**	**3,192**	**7,281**

(1) Excludes impact of hedge accounting and derivatives.

(2) The exchangeable debentures are due May 1, 2039 and the exchangeable preferred shares are perpetual. However, a cash payment could occur after Dec. 31, 2028, at the Company's option, if the exchangeable securities are not exchanged by Brookfield Renewable Partners or its affi iates (collectively Brookfield). At Brookfield's option, the exchangeable securities are currently exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets. (Note 26).

(3) Negative amount represents a receivable position or cash inflow.

(4) Not recognized as a financial liability on the Conso idated Statements of Financial Position and excludes the impact of interest rate swaps.

IV. Equity Price Risk

Total Return Swaps

The Company has certain compensation, deferred and restricted share unit programs, the values of which depend on the common share price of the Company. The Company has fixed a portion of the settlement cost of these programs by entering into a total return swap for which hedge accounting has not been applied. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price of the Company's common shares at the end of each quarter.

D. Hedging Instruments – Uncertainty of Future Cash Flows

The following table outlines the terms and conditions of derivative hedging instruments and how they affect the amount, timing and uncertainty of future cash flows:

	Maturity					
	2025	2026	2027	2028	2029	2030
Cash flow hedges						
Commodity derivative instruments						
Electricity						
Notional amount (thousands of MWh)	2,628	—	—	—	—	—
Average price ($ per MWh)	86.25	—	—	—	—	—

E. Effects of Hedge Accounting on Financial Position and Performance

I. Effect of Hedges

The impact of the hedging instruments on the statement of financial position is as follows:

As at Dec. 31, 2024	Notional amount	Carrying amount	Line item in the statement of financial position	Change in fair value used for measuring ineffectiveness
Commodity price risk				
Cash flow hedges				
Physical power sales[1]	**2,628**	**45**	**Risk management assets**	**114**
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	**USD300**	**CAD431**	**Credit facilities, long-term debt and lease liabilities**	**—**

(1) In thousands of MWh.

As at Dec. 31, 2023	Notional amount	Carrying amount	Line item in the statement of financial position	Change in fair value used for measuring ineffectiveness
Commodity price risk				
Cash flow hedges				
Physical power sales[1]	5,966	(205)	Risk management liabilities	(114)
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	USD370	CAD489	Credit facilities, long-term debt and lease liabilities	—

(1) In thousands of MWh.

The impact of the hedged items on the statement of financial position is as follows:

	2024		2023	
As at Dec. 31	Change in fair value used for measuring ineffectiveness	Cash flow hedge reserve[1]	Change in fair value used for measuring ineffectiveness	Cash flow hedge reserve[1]
Commodity price risk				
Cash flow hedges				
Power forecast sales – Centralia	**114**	**65**	(114)	(129)

	Change in fair value used for measuring ineffectiveness	Foreign currency translation reserve[1]	Change in fair value used for measuring ineffectiveness	Foreign currency translation reserve[1]
Foreign currency risk				
Net investment hedges				
Net investment in foreign subsidiaries	**—**	**(34)**	—	(36)

(1) Net of tax. Included in AOCI.

The hedging gain or loss recognized in OCI before tax is equal to the change in fair value used for measuring effectiveness for the net investment hedge. Ineffectiveness of $4 million in after-tax losses was reclassified from OCI to net earnings during the year ended Dec. 31, 2024.

The impact of designated cash flow hedges on OCI and net earnings is:

	Year ended Dec. 31, 2024				
	Effective portion			Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain recognized in OCI	Location of gain reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	**270**	Revenue	**(15)**	Revenue	—
Forward starting interest rate swaps	**—**	Interest expense	**(8)**	Interest expense	—
OCI impact	**270**	**OCI impact**	**(23)**	**Net earnings impact**	—

Over the next 12 months, the Company estimates that approximately $28 million of after-tax losses will be reclassified from AOCI to net earnings. These estimates assume constant natural gas and power prices, interest rates and exchange rates over time; however, the actual amounts that will be reclassified may vary based on changes in these factors.

Year ended Dec. 31, 2023

	Effective portion		Ineffective portion		
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
Commodity contracts	51	Revenue	83	Revenue	—
Forward starting interest rate swaps	—	Interest expense	(8)	Interest expense	—
OCI impact	51	OCI impact	75	Net earnings impact	—

Year ended Dec. 31, 2022

	Effective portion		Ineffective portion		
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
Commodity contracts	(747)	Revenue	124	Revenue	—
Forward starting interest rate swaps	53	Interest expense	2	Interest expense	—
OCI impact	(694)	OCI impact	126	Net earnings impact	—

II. Effect of Non-Hedges

For the year ended Dec. 31, 2024, the Company recognized a net unrealized loss of $7 million (2023 — loss of $44 million, 2022 — loss of $384 million) related to commodity derivatives.

For the year ended Dec. 31, 2024, a loss of $63 million (2023 — gain of $11 million, 2022 — gain of $20 million) related to foreign exchange and other derivatives was recognized, which consists of net unrealized losses of $36 million (2023 — gain of $27 million, 2022 — loss of $11 million) and net realized losses of $27 million (2023 — loss of $16 million, 2022 — gains of $31 million), respectively.

F. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2024, the Company provided $124 million (Dec. 31, 2023 — $145 million) in cash and cash equivalents as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents. Collateral provided is included within trade and other receivables in the Consolidated Statements of Financial Position. At Dec. 31, 2024, the Company provided $21 million (Dec. 31, 2023 — $19 million) in surety bonds as security for commodity trading activities.

II. Financial Assets Held as Collateral

At Dec. 31, 2024, the Company held $9 million (Dec. 31, 2023 — $9 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Company may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their contractual obligations or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract. Collateral held is related to physical and financial derivative transactions in a net asset position and is included in accounts payable and accrued liabilities in the Consolidated Statements of Financial Position.

III. Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Company's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Company's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs.

At Dec. 31, 2024, the Company had posted collateral of $424 million (Dec. 31, 2023 — $392 million) in the form of letters of credit on physical and financial derivative transactions in a net liability position. Certain derivative agreements contain credit-risk-contingent features, which if triggered could result in the Company having to post an additional $128 million (Dec. 31, 2023 — $154 million) of collateral to its counterparties.

16. Inventory

The components of inventory are as follows:

As at Dec. 31	2024	2023
Parts, materials and supplies	**85**	72
Coal	**27**	38
Emission credits	**18**	45
Natural gas	**4**	2
Total	**134**	157

No inventory was pledged as security for liabilities.

As at Dec. 31, 2024, the Company holds 460,585 emission credits in inventory that were purchased externally with a recorded book value of $18 million (Dec. 31, 2023 — 962,548 emission credits with a recorded book value of $45 million). The Company also has 2,109,491 (Dec. 31, 2023 — 3,121,837) of internally generated eligible emission credits from the Company's Wind and Solar and Hydro segments that have no recorded book value.

Emission credits can be sold externally or can be used to offset future emission obligations from our gas facilities located in Alberta, where the compliance price of carbon is expected to increase, resulting in a reduced cash cost for carbon compliance in the year of settlement.

During the second quarter of 2024, the Company used 978,894 emission credits with a carrying value of $22 million to settle a portion of the 2023 carbon compliance obligation. This resulted in the Company recognizing a reduction of $42 million in carbon compliance costs. The compliance price of carbon for the 2023 obligation settled was $65 per tonne. It increased to $80 per tonne in 2024.

During the second quarter of 2023, the Company settled the 2022 carbon compliance obligation in cash. The compliance price of carbon for the 2022 obligation settled was $50 per tonne.

17. Finance Lease Receivables

Amounts receivable under the Company's finance leases include the Mount Keith 132kV expansion (2024), Northern Goldfields solar facilities (2024 and 2023), the Poplar Creek cogeneration facility (2024 and 2023), the Muskeg River and the Primrose cogeneration plants (2024) and are as follows:

	2024		2023	
As at Dec. 31	**Minimum lease receipts**	**Present value of minimum lease receipts**	**Minimum lease receipts**	**Present value of minimum lease receipts**
Within one year	**48**	**47**	28	28
Second to fifth years inclusive	**185**	**159**	112	98
More than five years	**247**	**129**	117	64
	480	**335**	257	190
Less: unearned finance lease income	**146**	**—**	67	—
Add: unguaranteed residual value	**1**	**—**	—	—
Total finance lease receivables	**335**	**335**	190	190

Included in the Consolidated Statements of Financial Position as:		
Current portion of finance lease receivables (Note 13)	**30**	19
Long-term portion of finance lease receivables	**305**	171
Total finance lease receivables	**335**	190

During the first quarter of 2024, the Mount Keith 132kV expansion was completed. As a result, the Company derecognized assets under construction and recognized a finance lease receivable of $48 million. On Dec. 4, 2024, as part of the Heartland acquisition, the Company recognized current and non-current finance lease receivables of $8 million and $107 million, respectively (refer to Note 4 for details).

18. Assets Held for Sale

The change in assets held for sale is as follows:

	2024	2023
As at Jan. 1	**—**	—
Additions from acquisition of Heartland on Dec. 4, 2024 (Note 4)	80	—
Balance, Dec. 31	**80**	—

19. Property, Plant and Equipment

A reconciliation of the changes in the carrying amount of PP&E is as follows:

	Assets under construction	Land	Hydro	Wind and Solar	Gas generation	Energy Transition	Capital spares and other[1]	Total
Cost								
As at Dec. 31, 2022	963	93	840	3,233	4,530	3,974	379	14,012
Additions[2]	869	—	—	—	—	—	6	875
Disposals	—	(3)	—	—	—	(30)	—	(33)
Impairment reversals (Note 7)	—	—	10	4	—	—	—	14
Changes to decommissioning and restoration costs	—	—	3	14	(22)	3	(1)	(3)
Retirement of assets	—	—	(7)	(18)	(124)	(7)	(108)	(264)
Change in foreign exchange rates	(26)	—	—	(18)	(7)	(42)	(1)	(94)
Transfers of assets[3]	(572)	—	38	439	50	16	31	2
Transfers to finance lease receivable	—	—	—	(61)	(4)	—	—	(65)
As at Dec. 31, 2023	1,234	90	884	3,593	4,423	3,914	306	14,444
Additions[2]	**279**	**—**	**—**	**—**	**10**	**—**	**22**	**311**
Acquisitions (Note 4)	**11**	**—**	**—**	**—**	**401**	**—**	**—**	**412**
Disposals	**—**	**(2)**	**—**	**—**	**(1)**	**(3)**	**—**	**(6)**
Changes to decommissioning and restoration costs (Note 24)	**—**	**—**	**16**	**9**	**13**	**—**	**—**	**38**
Retirement of assets	**—**	**—**	**(10)**	**(12)**	**(16)**	**—**	**—**	**(38)**
Change in foreign exchange rates	**28**	**2**	**—**	**124**	**—**	**146**	**2**	**302**
Transfer to intangible assets (Note 21)	**—**	**—**	**—**	**—**	**(163)**	**—**	**—**	**(163)**
Transfers of assets[3]	**(1,432)**	**—**	**43**	**1,205**	**163**	**14**	**7**	**—**
Transfers to finance lease receivable (Note 17)	**—**	**—**	**—**	**—**	**(48)**	**—**	**—**	**(48)**
As at Dec. 31, 2024	**120**	**90**	**933**	**4,919**	**4,782**	**4,071**	**337**	**15,252**
Accumulated depreciation								
As at Dec. 31, 2022	—	—	478	1,228	2,812	3,744	194	8,456
Depreciation	—	—	25	129	342	73	16	585
Retirement of assets	—	—	(4)	(15)	(101)	(7)	(108)	(235)
Disposals	—	—	—	—	—	(30)	—	(30)
Change in foreign exchange rates	—	—	—	(5)	(3)	(39)	—	(47)
Transfers of assets[3]	—	—	—	—	(1)	2	—	1
As at Dec. 31, 2023	—	—	499	1,337	3,049	3,743	102	8,730
Depreciation	**—**	**—**	**37**	**170**	**221**	**62**	**28**	**518**
Retirement of assets	**—**	**—**	**(9)**	**(9)**	**(15)**	**—**	**—**	**(33)**
Disposals	**—**	**—**	**—**	**—**	**—**	**(2)**	**—**	**(2)**
Change in foreign exchange rates	**—**	**—**	**—**	**23**	**1**	**138**	**—**	**162**
Transfer to intangible assets (Note 21)	**—**	**—**	**—**	**—**	**(143)**	**—**	**—**	**(143)**
As at Dec. 31, 2024	**—**	**—**	**527**	**1,521**	**3,113**	**3,941**	**130**	**9,232**
Carrying amount								
As at Dec. 31, 2022	963	93	362	2,005	1,718	230	185	5,556
As at Dec. 31, 2023	1,234	90	385	2,256	1,374	171	204	5,714
As at Dec. 31, 2024	**120**	**90**	**406**	**3,398**	**1,669**	**130**	**207**	**6,020**

(1) Includes major spare parts and standby equipment available, but not in service.

(2) In 2024, the Company capitalized $16 million (2023 — $57 million) of interest to PP&E at a weighted average rate of 6.52 per cent (2023 — 6.3 per cent).

(3) Includes transfers of assets upon commissioning to assets in service and other movements.

Assets under Construction

During the year, the Company achieved commercial operations at the White Rock and Horizon Hill wind facilities. Costs were transferred from assets under construction to the Wind and Solar segment. As outlined in Note 17, $48 million related to the Mount Keith 132kV expansion was derecognized from assets under construction and recognized as a finance lease receivable in the first quarter of 2024.

Change in Estimate — Useful Lives

During 2024 and 2023, the Company adjusted the useful lives of certain assets in the Gas segment to reflect changes to the future operating expectations of the assets. The adjustment to the useful lives resulted in a decrease of $112 million (2023 — $92 million) in depreciation expense that was recognized in the Consolidated Statement of Earnings.

Mothballing of Sundance Unit 6

During 2024, the Company announced it will temporarily mothball Sundance Unit 6 on April 1, 2025 for a period of up to two years depending on market conditions. The Company maintains the flexibility to return the mothballed unit to service when market fundamentals improve or opportunities to contract are secured. The unit remains available and fully operational for the first quarter of 2025.

20. Right-of-Use Assets

The Company leases various properties and types of equipment. Lease contracts are typically made for fixed periods. Leases are negotiated on an individual basis and contain a wide range of terms and conditions.

The lease agreements do not impose covenants, but leased assets may not be used as security for borrowing purposes.

A reconciliation of the changes in the carrying amount of the right-of-use assets is as follows:

	Land	Buildings	Vehicles	Equipment	Total
As at Dec. 31, 2022	102	15	2	7	126
Additions	2	2	1	—	5
Depreciation	(5)	(5)	—	(2)	(12)
Change in foreign exchange rates	(2)	—	—	—	(2)
As at Dec. 31, 2023	97	12	3	5	117
Additions[1]	**1**	**3**	**1**	**—**	**5**
Depreciation	**(5)**	**(1)**	**(1)**	**(1)**	**(8)**
Change in foreign exchange rates	**6**	**—**	**—**	**—**	**6**
As at Dec. 31, 2024	**99**	**14**	**3**	**4**	**120**

(1) Additions to buildings include right-of-use assets of $1 mil ion acquired from Heartland.

For the year ended Dec. 31, 2024, TransAlta paid $16 million (2023 — $19 million) related to recognized lease liabilities, consisting of $6 million (2023 — $10 million) of principal repayments and $10 million (2023 — $9 million) of interest expense.

Short-term leases (term of less than 12 months) and leases with total lease payments below the Company's capitalization threshold (low value leases) do not require recognition as lease liabilities and right-of-use assets. For the year ended Dec. 31, 2024, the Company expensed $1 million (2023 — $1 million and 2022 — $2 million) related to short-term and low value leases.

Some of the Company's land leases that met the definition of a lease were not recognized as they require variable payments based on production or revenue.

Additionally, certain land leases require payments to be made on the basis of the greater of the minimum fixed payments and variable payments based on production or revenue. For these leases, lease liabilities have been recognized on the basis of the minimum fixed payments. For the year ended Dec. 31, 2024, the Company expensed $9 million (2023 — $8 million and 2022 — $8 million) in variable land lease payments for these leases.

21. Intangible Assets

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Power sale and other contracts	Software and other	Intangibles under development	Coal rights	Total
Cost					
As at Dec. 31, 2022	272	437	27	132	868
Additions	—	—	13	—	13
Asset impairment charges (Note 7)	—	(1)	—	—	(1)
Change in foreign exchange rates	(2)	(2)	(1)	—	(5)
Transfers	—	12	(12)	—	—
As at Dec. 31, 2023	270	446	27	132	875
Additions	—	—	**10**	—	**10**
Acquisitions (Note 4)	**57**	**—**	—	**—**	**57**
Change in foreign exchange rates	**5**	**7**	**1**	—	**13**
Transfers	**20**	**35**	**(33)**	—	**22**
As at Dec. 31, 2024	**352**	**488**	**5**	**132**	**977**
Accumulated amortization					
As at Dec. 31, 2022	158	326	—	132	616
Amortization	17	21	—	—	38
Change in foreign exchange rates	(1)	(1)	—	—	(2)
As at Dec. 31, 2023	174	346	—	132	652
Amortization	**19**	**19**	**—**	**—**	**38**
Change in foreign exchange rates	**4**	**3**	**—**	**—**	**7**
Transfers	**—**	**(1)**	**—**	**—**	**(1)**
As at Dec. 31, 2024	**197**	**367**	**—**	**132**	**696**
Carrying amount					
As at Dec. 31, 2022	114	111	27	—	252
As at Dec. 31, 2023	96	100	27	—	223
As at Dec. 31, 2024	**155**	**121**	**5**	**—**	**281**

22. Goodwill

Goodwill acquired through business combinations has been allocated to groups of CGUs that are expected to benefit from the synergies of the acquisitions. Goodwill by segments is as follows:

As at Dec. 31	2024	2023
Hydro	**258**	258
Wind and Solar	**178**	176
Gas (Note 4)	**51**	—
Energy Marketing	**30**	30
Total goodwill	**517**	464

Addition to goodwill in the Gas segment in 2024 represents the excess of the purchase price over the estimated fair value of the net assets acquired in the business acquisition of Heartland. Refer to Note 4 for more details.

For the purposes of the 2024 goodwill impairment review, the Company determined the recoverable amounts of the Wind and Solar segment by calculating the fair value less costs of disposal using discounted cash flow projections. In 2024, the Company relied on the recoverable amounts determined in 2022 for the Hydro and Energy Marketing segments in performing the 2024 goodwill impairment review. The recoverable amounts are based on the Company's long-range forecasts for the periods extending to the last planned asset retirement in 2072. The resulting fair value measurements are categorized within Level III of the fair value hierarchy. No impairment of goodwill arose for any segment.

The significant assumptions impacting the determination of fair value for the Wind and Solar segment, with a high degree of subjectivity, are the following:

- Forecasts of sales prices for each facility are determined by taking into consideration contract prices for facilities subject to long- or short-term contracts, forward price curves for merchant plants and regional supply-demand balances. Where forward price curves are not available for the duration of the facility's useful life, prices are determined by extrapolation techniques using historical industry and Company-specific data. Merchant electricity prices used in Wind and Solar models ranged between $40 to $225 per MWh during the forecast period (2023 — $35 to $238 per MWh).
- Discount rates used ranged from 6.4 per cent to 7.3 per cent (2023 — 6.4 per cent to 7.5 per cent). A 0.5 per cent increase in the discount rate would not impact the results of the impairments tests performed.
- The White Rock and the Horizon Hill wind facilities are subject to location-specific price basis, sourced from third-party analysis. This analysis is based on models of the transmission system, including assumptions around potential system upgrades as well as forecasted generation and load in the area.

23. Other Assets

The components of other assets are as follows:

As at Dec. 31	2024	2023
South Hedland prepaid transmission access and distribution costs	**58**	60
TransAlta Energy Transition Bill commitment	**30**	32
Long-term prepaids and other assets	**35**	9
Project development costs	**15**	35
Loans receivable	**25**	26
Transmission infrastructure	**17**	18
Total other assets	**180**	180
Included in the Consolidated Statements of Financial Position as:		
Total current other assets (Note 13)	**1**	1
Total long-term other assets	**179**	179
Total other assets	**180**	180

South Hedland prepaid transmission access and distribution costs are costs that are amortized on a straight-line basis over the South Hedland PPA contract life.

As part of the TransAlta Energy Transition Bill signed into law in the State of Washington and the subsequent Memorandum of Agreement (MOA), the Company committed to fund US$55 million in total over the remaining life of the Centralia coal plant to support economic and community development, promote energy efficiency and develop energy technologies related to the improvement of the environment. The MOA contains certain provisions for termination and in the event of termination and in certain circumstances, this funding or portion thereof would no longer be required. As at Dec. 31, 2023, the Company has fully funded the commitment. The outstanding balance will be expensed to net earnings when the funds are granted and disbursed to organizations.

Long-term prepaids and other assets include contractually required prepayments and deposits, including the balances acquired from Heartland. Refer to Note 4 for more details.

Project development costs primarily include the pre-construction project costs, which met the criteria for capitalization.

At Dec. 31, 2024, $25 million of the loans receivable (2023 — $26 million) is an unsecured loan related to an advancement by the Company's subsidiary, Kent Hills Wind LP, of the net financing proceeds of the Kent Hills Wind Bond (KH Bonds), to its 17 per cent partner. The loan bears interest at 4.55 per cent, with interest payable quarterly. No scheduled principal repayments are required until the maturity date of October 2027. During 2024, no repayments were required as part of the waiver and amendment made to the KH Bonds (2023 — repayments of $12 million).

Transmission infrastructure was constructed by the Company and then transferred to a transmission provider upon completion. The balance relates to the Garden Plain and Windrise wind facilities and will be amortized to net earnings over the useful life of the facilities.

24. Decommissioning and Other Provisions

The change in decommissioning and other provision balances is as follows:

	Decommissioning and restoration	Other provisions	Total
Dec. 31, 2022	688	41	729
Liabilities incurred	1	4	5
Liabilities settled	(37)	(13)	(50)
Accretion	47	1	48
Revisions in estimated cash flows	(89)	—	(89)
Revisions in discount rates	52	—	52
Change in foreign exchange rates	(6)	—	(6)
Balance, Dec. 31, 2023	656	33	689
Liabilities acquired (Note 4)	**101**	**55**	**156**
Liabilities incurred	**6**	**12**	**18**
Liabilities settled	**(41)**	**(4)**	**(45)**
Accretion (Note 10)	**50**	**—**	**50**
Transfer to accounts payable	**—**	**(31)**	**(31)**
Transfer to assets held for sale (Note 18)	**(1)**	**—**	**(1)**
Revisions in estimated cash flows	**21**	**20**	**41**
Revisions in discount rates	**35**	**—**	**35**
Change in foreign exchange rates	**21**	**—**	**21**
Balance, Dec. 31, 2024	**848**	**85**	**933**

Included in the Consolidated Statements of Financial Position as:

As at	Dec. 31, 2024	Dec. 31, 2023
Current portion	**83**	35
Non-current portion	**850**	654
Total decommissioning and other provisions	**933**	689

A. Decommissioning and Restoration

A provision has been recognized for all generating facilities and mines for which TransAlta is legally, or constructively, required to remove the facilities at the end of their useful lives and restore the sites to their original condition. TransAlta estimates that the undiscounted amount of cash flow required to settle these obligations is approximately $1.8 billion, which will be incurred between 2025 and 2072. The majority of the costs will be incurred between 2025 and 2050.

On Dec. 4, 2024 as part of the Heartland acquisition, the Company recognized decommissioning and restoration provision of $101 million and other provisions of $55 million (refer to Note 4 for details).

During 2024, the decommissioning and restoration provision increased by $21 million due to revisions in estimated cash flows and timing of cash flows for certain Gas and Hydro assets. The timing of cash flows was adjusted to optimize and maximize efficiencies by staging required reclamation work. Operating assets included in PP&E increased by $14 million and $7 million was recognized as an impairment charge in net earnings related to retired assets.

During 2024, revisions in discount rates increased the decommissioning and restoration provision by $35 million due to a decrease in discount rates, largely driven by decreases in long-term market benchmark rates. On average, discount rates decreased compared to 2023, with rates ranging from 5.3 to 8.4 per cent as at Dec. 31, 2024. This has resulted in a corresponding increase in PP&E of $18 million on operating assets and the recognition of a $17 million impairment charge in net earnings related to retired assets.

During 2023, the decommissioning and restoration provision decreased by $89 million due to revisions in estimated cash flows and timing of cash flows for certain Gas and Energy Transition assets. The timing of cash flows was adjusted to optimize and maximize efficiencies by staging required reclamation work. Operating assets included in PP&E decreased by $34 million and $55 million was recognized as an impairment reversal in net earnings related to retired assets.

During 2023, revisions in discount rates increased the decommissioning and restoration provision by $52 million due to a decrease in discount rates, largely driven by decreases in long-term market benchmark rates. On average, discount rates decreased compared to 2022, with rates ranging from 6.0 to 9.0 per cent as at Dec. 31, 2023. This has resulted in a corresponding increase in PP&E of $31 million on operating assets and the recognition of a $21 million impairment charge in net earnings related to retired assets.

At Dec. 31, 2024, the Company has provided a surety bond in the amount of US$147 million (2023 — US$147 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2024, the Company had provided a surety bond and letters of credit in the amount of $194 million (2023 — $188 million) in support of future decommissioning obligations at the Highvale mine.

B. Other Provisions

Other provisions include provisions arising from ongoing business activities, amounts related to commercial disputes between the Company and customers or suppliers and onerous contract provisions. Information about the expected timing of settlement and uncertainties that could impact the amount or timing of settlement has not been provided as this may impact the Company's ability to settle the provisions in the most favourable manner.

As part of the acquisition of Heartland, the Company recognized an onerous contract provision of $47 million related to certain natural gas transportation contracts assumed. Payments required under the contracts continue through the first quarter of 2031.

25. Credit Facilities, Long-Term Debt and Lease Liabilities

A. Amounts Outstanding

The amounts outstanding are as follows:

				2024			2023		
As at Dec. 31	Segment	Maturity	Currency	Carrying value	Face value	Interest[1]	Carrying value	Face value	Interest
Credit facilities									
Committed syndicated bank facility[2]	Corporate	2028	CAD	**143**	**145**	**5.3%**	—	—	—%
Term Faci ity	Corporate	2025	CAD	**400**	**400**	**5.6%**	397	400	7.4%
Debentures									
7.3% Medium term notes	Corporate	2029	CAD	**110**	**110**	**7.3%**	110	110	7.3%
6.9% Medium term notes	Corporate	2030	CAD	**141**	**141**	**6.9%**	141	141	6.9%
Senior notes[3]									
7.8% Senior notes[4]	Corporate	2029	USD	**569**	**575**	**7.8%**	520	528	7.8%
6.5% Senior notes	Corporate	2040	USD	**426**	**431**	**6.5%**	391	396	6.5%
Non-recourse									
Melancthon Wolfe Wind LP bond	Wind & Solar	2028	CAD	**133**	**134**	**3.8%**	168	169	3.8%
New Richmond Wind LP bond	Wind & Solar	2032	CAD	**93**	**94**	**4.0%**	103	104	4.0%
Kent Hills Wind LP bond	Wind & Solar	2033	CAD	**179**	**182**	**4.5%**	193	196	4.5%
Windrise Wind LP bond	Wind & Solar	2041	CAD	**157**	**160**	**3.4%**	164	167	3.4%
Pingston bond	Hydro	2043	CAD	**39**	**39**	**6.2%**	39	39	6.2%
TAPC Holdings LP bond (Poplar Creek)	Gas	2030	CAD	**75**	**76**	**8.3%**	85	86	9.4%
TEC Hedland PTY Ltd bond[5]	Gas	2042	AUD	**675**	**683**	**4.1%**	691	699	4.1%
Heartland term facility	Corporate	2027	CAD	**224**	**224**	**6.6%**	—	—	—%
Recourse									
TransAlta OCP LP bond	Gas	2030	CAD	**192**	**193**	**4.5%**	217	218	4.5%
Tax equity financing									
Big Level & Antrim[6]	Wind & Solar	2029	USD	**90**	**94**	**6.6%**	91	97	6.6%
Lakeswind[7]	Wind & Solar	2027	USD	**7**	**7**	**10.5%**	10	10	10.5%
North Carolina Solar[8]	Wind & Solar	2028	USD	**4**	**4**	**7.3%**	3	3	7.3%
Total long-term debt				**3,657**	**3,692**		3,323	3,363	
Lease iabi ities				**151**			143		
Total long-term debt and lease liabilities				**3,808**			3,466		
Less: current portion of long-term debt				**(567)**			(526)		
Less: current portion of lease liabi ities				**(5)**			(6)		
Total current long-term debt and lease liabilities				**(572)**			(532)		
Total non-current credit facilities, long-term debt and lease liabilities				**3,236**			2,934		

(1) Interest rate reflects the stipulated rate or the average rate weighted by principal amounts outstanding and is before the effect of hedging.

(2) Composed of swing line loans and other commercial borrowings under long-term committed credit facilities.

(3) U.S. face value at Dec. 31, 2024, is US$700 million (2023 — US$700 million).

(4) The effective interest rate for the Senior Notes is 5.98 per cent after the effects of gains realized on settled interest rate hedging instruments.

(5) AU face value at Dec. 31, 2024, is AU$761 mil ion (2023 — AU$773 million).

(6) U.S. face value at Dec. 31, 2024, is US$65 million (2023 — US$73 mil ion).

(7) U.S. face value at Dec. 31, 2024, is US$5 million (2023 — US$8 million).

(8) U.S. face value at Dec. 31, 2024, is US$3 million (2023 — US$2 mil ion).

The Company's credit facilities are summarized in the table below:

As at Dec. 31, 2024		Utilized			
Credit facilities	Facility size	Outstanding letters of credit[1]	Cash drawings	Available capacity	Maturity date
Committed					
Syndicated credit facility	1,950	456	145	1,349	Q2 2028
Bilateral credit facilities	240	161	—	79	Q2 2026
Term Facility	400	—	400	—	Q3 2025
Heartland Credit Facilities	276	14	224	38	Q4 2027
Heartland EDC letter of credit facility	50	14	—	36	Q1 2025
Total committed	**2,916**	**645**	**769**	**1,502**	
Non-committed					
Demand facilities	400	220	—	180	N/A
Total Non-committed	**400**	**220**	**—**	**180**	

(1) TransAlta has obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, pension plan obligations, construction projects and purchase obligations. Letters of credit drawn against the non-committed facilities reduce the available capacity under the committed syndicated credit facilities. At Dec. 31, 2024, TransAlta provided cash collateral of $124 million.

In the second quarter of 2024, the Term Facility of $400 million was renewed with the maturity extended by one year to September 2025. The syndicated credit facility and bilateral credit facilities were also extended by one year to June 2028 and June 2026, respectively.

The credit facilities are the primary source of short-term liquidity after the cash flow generated from the Company's business.

Heartland Credit Facilities

As part of the Heartland acquisition on Dec. 4, 2024, the Company assumed a $232 million drawn term facility and a $25 million revolving facility with a syndicate of banks, (collectively Heartland Credit Facilities). At Dec. 31, 2024 the drawn term facility was $224 million. The $25 million revolving facility is undrawn and available for working capital and general corporate purposes. The maturity date for the Heartland Credit Facilities is Dec. 22, 2027. The Heartland Credit Facilities also include a $27 million debt service reserve letter of credit facility. As at Dec. 31, 2024 $14 million in letters of credit have been issued under this facility.

Heartland EDC Letter of Credit Facility

As part of the Heartland acquisition, the Company has access to a $50 million unsecured letter of credit facility with two Canadian banks, which is supported by a performance security guarantee from Export Development Canada (EDC). As at Dec. 31, 2024, $14 million in letters of credit have been issued under this facility. The facility is effective until March 31, 2025.

Senior Notes

A total of US$300 million (2023 — US$370 million) of the senior notes have been designated as a hedge of the Company's net investment in U.S. operations.

Non-Recourse Debt

On May 8, 2023, the Pingston Power Inc. non-recourse bond matured with a total aggregate repayment of $46 million, consisting of accrued interest and principal.

On Sept. 14, 2023, the Company closed a non-recourse bond financing for approximately $39 million (Pingston Bond) as a replacement for the non-recourse bond that matured on May 8, 2023. The Pingston Bond is secured by a first ranking charge over all the respective assets of the Company's subsidiaries that issued the bonds, amortizes and bears interest at a rate of 6.145 per cent per annum, payable semi-annually, and matures on May 8, 2043. The Pingston Bond is subject to customary financing conditions and covenants that may restrict the Company's ability to access funds generated by the facility's operations.

Tax Equity

Tax equity financings are typically represented by the initial equity investments made by the project investors at each project (net of financing costs incurred), except for the Lakeswind and North Carolina Solar acquired tax equity financings, which were initially recognized at their fair values. Tax equity financing balances are reduced by the value of tax benefits (production tax credits, tax depreciation and investment tax credits) allocated to the investor and by cash distributions paid to the investor for

their share of net earnings and cash flow generated at each project. Tax equity financing balances are increased by interest recognized at the implicit interest rate. The maturity dates of each financing are subject to change and are primarily dependent upon when the project investor achieves the agreed upon targeted rate of return. The Company anticipates the maturity dates of the tax equity financings will be: Lakeswind in June 2027; North Carolina Solar in December 2028; and Big Level and Antrim in December 2029.

Other

TransAlta's short and long-term debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2024, the Company was in compliance with all debt covenants.

The Heartland Credit Facilities are not subject to any maintenance or financial covenants but do contain certain covenants that limit Heartland's ability to, among other things, incur additional indebtedness, create or permit liens to exist, make certain acquisitions or dispositions, make distributions and enter into certain hedging agreements.

The Company is in compliance with its terms of the credit facilities and all undrawn amounts are fully available. Letters of credit in the amount of $220 million were issued from non-committed demand facilities as at Dec. 31, 2024. In addition to the net $1.5 billion of committed capacity available under the credit facilities, the Company had $336 million of available cash and cash equivalents as at Dec. 31, 2024.

B. Restrictions Related to Non-Recourse Debt and Other Debt

The Melancthon Wolfe Wind LP, Pingston Power Inc., TAPC Holdings LP, New Richmond Wind LP, Kent Hills Wind LP, TEC Hedland Pty Ltd. and Windrise Wind LP non-recourse bonds, the TransAlta OCP LP bond, and Heartland Credit Facilities, with a total carrying value of $1.8 billion as at Dec. 31, 2024 (2023 — $1.7 billion), are subject to customary financing conditions and covenants that may restrict the Company's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds can be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the fourth quarter of 2024 with the exception of Kent Hills Wind LP. The funds in the entities will remain there until the next debt service coverage ratio can be performed in the first quarter of 2025. At Dec. 31, 2024, $117 million (2023 — $79 million) of cash was subject to these financial restrictions.

At Dec. 31, 2024, $5 million (AU$6 million) of funds held by TEC Hedland Pty Ltd. cannot be accessed by other corporate entities as the funds must be solely used by the project entities, for the purpose of paying major maintenance costs. Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit.

C. Security

Non-recourse debt totalling $1.5 billion as at Dec. 31, 2024 (2023 — $1.4 billion) is secured by a first ranking charge over all of the respective assets of the Company's subsidiaries that issued the debt, which include PP&E with total carrying amounts of $1.75 billion at Dec. 31, 2024 (2023 — $1.5 billion) and intangible assets with total carrying amounts of $84 million (2023 — $61 million). At Dec. 31, 2024, non-recourse debt of approximately $75 million (2023 — $85 million) was secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse debt.

The TransAlta OCP bonds have a carrying value of $192 million (2023 — $217 million) and are secured by the assets of TransAlta OCP, including the right to annual capital contributions and OCA payments from the Government of Alberta related to TransAlta's legacy coal facilities (the TransAlta OCA). Under the TransAlta OCA, the Company receives annual cash payments on or before July 31 of approximately $40 million (approximately $37 million, net to the Company), commencing on Jan. 1, 2017, and terminating at the end of 2030. These payments do not include the OCA payments Heartland is entitled to under its OCA.

D. Principal Repayments

	2025	2026	2027	2028	2029	2030 and thereafter	Total
Principal repayments[1]	566	169	331	309	824	1,493	**3,692**
Lease liabilities	4	5	5	5	5	127	**151**

(1) Excludes impact of hedge accounting and derivatives.

E. Restricted Cash

As at Dec. 31, 2024, the Company had $17 million (2023 — $17 million) of restricted cash related to the TransAlta OCP bonds, which is required to be held in a debt service reserve account to fund scheduled future debt repayments. The Company also had $52 million (2023 — $52 million) of restricted cash related to the TEC Hedland Pty Ltd. bond. These cash reserves are required to be held under commercial arrangements and for debt service, which may be replaced by letters of credit in the future.

F. Letters of Credit

Letters of credit are issued to counterparties as required by various contractual arrangements with the Company and certain subsidiaries of the Company. If the Company or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business. The total outstanding letters of credit as at Dec. 31, 2024, was $865 million (2023 — $782 million) with nil (2023 — nil) amounts exercised by third parties under these arrangements.

G. Currency Impacts

The strengthening of the U.S. dollar has increased the U.S. dollar denominated long-term debt balances, mainly the senior notes and tax equity financings, by $90 million as at Dec. 31, 2024 (2023 — decreased $27 million due to the weakening of the U.S. dollar). Almost all of the U.S. dollar denominated debt is hedged either through financial contracts or net investments in U.S. operations.

Additionally, the weakening of the Australian dollar has decreased the Australian dollar-denominated non-recourse senior secured notes balance by approximately $5 million as at Dec. 31, 2024 (2023 — $9 million). As this debt is issued by an Australian subsidiary, the foreign currency translation impacts are recognized within other comprehensive income (loss).

26. Exchangeable Securities

On March 22, 2019, the Company entered into an Investment Agreement whereby Brookfield Renewable Partners or its affiliates (collectively Brookfield) agreed to invest $750 million in TransAlta through the purchase of exchangeable securities, which are exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets in the future at a value based on a multiple of the Alberta Hydro Assets' future-adjusted EBITDA (Option to Exchange).

A. $750 Million Exchangeable Securities

	Dec. 31, 2024			Dec. 31, 2023		
As at	Carrying value	Face value	Interest	Carrying value	Face value	Interest
Exchangeable debentures – due May 1, 2039[1]	**350**	**350**	**7%**	344	350	7%
Exchangeable preferred shares[2]	**400**	**400**	**7%**	400	400	7%
Total exchangeable securities	**750**	**750**		744	750	

(1) Seven per cent unsecured subordinated debentures due May 1, 2039.

(2) Redeemable, retractable first preferred shares (Series I). Exchangeable preferred share dividends are reported as interest expense.

On Dec. 9, 2024, the Company declared a dividend of $7 million, in aggregate, for the Exchangeable Preferred Shares at the fixed rate of 1.760 per cent, per share, payable on Feb. 28, 2025. The Exchangeable Preferred Shares are considered debt for accounting purposes and, as such, dividends are reported as interest expense (Note 10).

B. Option to Exchange

As at	Dec. 31, 2024		Dec. 31, 2023	
Description	Base fair value	Sensitivity	Base fair value	Sensitivity
Option to exchange – embedded derivative	—	**+nil** **-30**	—	+nil -25

The Investment Agreement allows Brookfield the option to exchange all of the outstanding exchangeable securities after Dec. 31, 2024, into an equity ownership interest of up to a maximum 49 per cent in an entity that has been formed to hold the Alberta Hydro Assets. The fair value of the option to exchange is considered a Level III fair value measurement as there is no available market-observable data. It is therefore valued using a mark-to-forecast model with inputs that are based on historical data and changes in underlying discount rates only when it represents a long-term change in the value of the option to exchange.

Sensitivity ranges for the base fair value are determined using reasonably possible alternative assumptions for key unobservable inputs, which is mainly the change in the implied discount rate of future cash flows. The sensitivity analysis has been prepared using the Company's assessment that a change in the implied discount rate of 10.5 per cent (2023 — 11.8 per cent) of future cash flows of one per cent is a reasonably possible change.

The maximum equity interest Brookfield can own with respect to the Alberta Hydro Assets is 49 per cent. If Brookfield's ownership interest is less than 49 per cent at conversion, Brookfield has a one-time option payable in cash to increase its ownership to up to 49 per cent, exercisable up until Dec. 31, 2028, provided Brookfield holds at least 8.5 per cent of TransAlta's common shares. Under this top-up option, Brookfield will be able to acquire an additional 10 per cent interest in the entity holding the Alberta Hydro Assets, provided the 20-day volume-weighted average price (VWAP) of TransAlta's common shares is not less than $14 per share prior to the exercise of the option, and up to the full 49 per cent if the 20-day VWAP of TransAlta's common shares at that time is not less than $17 per share. To the extent the value of the investment would exceed a 49 per cent equity interest, Brookfield will be entitled to receive the balance of the redemption price in cash.

In connection with the Investment Agreement, Brookfield is entitled to nominate two directors for election to the Board.

27. Defined Benefit Obligation and Other Long-Term Liabilities

The components of defined benefit obligation and other long-term liabilities are as follows:

As at Dec. 31	2024	2023
Defined benefit obligation (Note 32)	**146**	155
Retail power contract liability	**45**	83
Other	**11**	13
Total	**202**	251

The liability for pension and post-employment benefits and associated costs included in compensation expenses are impacted by estimates related to changes in key actuarial assumptions, including discount rates. The defined benefit obligation has decreased by $9 million to $146 million as at Dec. 31, 2024, from $155 million as at Dec. 31, 2023.

The Company's U.S. Defined Benefit Pension Plan was terminated effective June 30, 2024 and annuitized with the TransAlta Retirement Pension Plan Trust in October 2024. Plan assets and liabilities both totalling $23 million (US$17 million) were transferred to a new provider. The participant payments with a new provider commenced on Jan. 1, 2025.

During 2023, the Company made a voluntary contribution of $4 million (US$3 million) to further improve the funded status of U.S. Defined Benefit Pension Plan for the Centralia thermal facility.

A one per cent increase in discount rates would result in a $34 million decrease in the defined benefit obligation. Refer to Note 32 for additional sensitivities impacting the defined benefit obligation.

The retail power contract liability represents an obligation arising from the purchase and sale agreement for customer retail contracts to deliver power, gas and power and gas financial swaps. The retail power contracts represent certain off-market customer contracts, where the value of the contract is based on the differential between the contractual and market rates on the closing date. The retail contract liability is amortized to depreciation over the remaining term of the contracts based on volumes that will be delivered each month.

28. Common Shares

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value.

	2024		2023	
As at Dec. 31	Common shares (millions)	Amount	Common shares (millions)	Amount
Issued and outstanding, beginning of period	**306.9**	**3,285**	268.1	2,863
Reversal of provision for repurchase of common shares under ASPP	**1.7**	**19**	—	—
Purchased and cancelled under the NCIB[1][2]	**(13.5)**	**(146)**	(7.5)	(80)
Share-based payment plans	**0.8**	**9**	0.8	6
Stock options exercised	**1.6**	**12**	0.7	5
Issued for acquisition of TransAlta Renewables[3] (Note 4)	**—**	**—**	46.5	510
Issued and outstanding, end of year, prior to ASPP	**297.5**	**3,179**	308.6	3,304
Provision for repurchase of common shares under ASPP	**—**	**—**	(1.7)	(19)
Issued and outstanding, end of year	**297.5**	**3,179**	306.9	3,285

(1) 2024 includes $2 million of tax on share buybacks (2023 — nil) on the fair value of the shares repurchased.

(2) Shares purchased by the Company under the NCIB (as defined below) are recognized as a reduction to share capital equal to the average carrying value of the common shares. Any difference between the aggregate purchase price and the average carrying value of the common shares is recorded in retained earnings (deficit).

(3) Net of $4 million of transaction costs.

B. Normal Course Issuer Bid (NCIB) Program

The effects of the Company's purchase and cancellation of common shares during the period are as follows:

For the year ended Dec. 31	2024	2023
Total shares purchased	**13,467,400**	7,537,500
Average purchase price per share	**10.59**	11.49
Total cost (millions)	**143**	87
Book value of shares cancelled	**146**	80
Amount recorded in deficit	**3**	(7)

2024

On May 27, 2024, the Company announced that it received approval from the Toronto Stock Exchange (TSX) to repurchase up to a maximum of 14 million common shares during the 12-month period that commenced May 31, 2024, and terminates May 30, 2025. Any common shares purchased under the NCIB will be cancelled.

2023

On May 26, 2023, the TSX accepted the notice filed by the Company to renew its NCIB for a portion of its common shares.

On Dec. 19, 2023, the Company entered into an Automatic Share Purchase Plan (ASPP) that permits an independent broker to repurchase shares under the NCIB during the first quarter blackout period through to the end of the ASPP. As at Dec. 31, 2023, the Company recognized a

provision of $19 million for the repurchase of common shares under the ASPP within accounts payables and accrued liabilities as an estimate of the maximum number of shares that could be repurchased during the blackout period. The provision was settled during 2024.

C. Shareholder Rights Plan

The Company initially adopted the Shareholder Rights Plan in 1992, which was amended and restated on April 28, 2022. As required, the Shareholder Rights Plan must be put before the Company's shareholders every three years for approval. It was last approved on April 28, 2022, and will need to be approved at the annual meeting of shareholders in 2025. The primary objective of the Shareholder Rights Plan is to encourage a potential acquirer to meet certain minimum standards designed to promote the fair and equal treatment of all common shareholders. When an acquiring shareholder acquires 20 per cent or more of the Company's common shares, except in limited circumstances including by way of a "permitted bid" or a "competing permitted bid" (as defined in the Shareholder Rights Plan), the rights granted under the Shareholder Rights Plan become exercisable by all shareholders except those held by the acquiring shareholder. Each right will entitle a shareholder, other than the acquiring shareholder, to purchase additional common shares at a significant discount to market, thus exposing the person acquiring 20 per cent or more of the shares to substantial dilution of their holdings.

D. Earnings per Share

Year ended Dec. 31	2024	2023	2022
Net earnings attributable to common shareholders	**177**	644	4
Basic and diluted weighted average number of common shares outstanding (millions)	**302**	276	271
Net earnings per share attributable to common shareholders, basic and diluted	**0.59**	2.33	0.01

E. Dividends

On Dec. 9, 2024, the Company declared a quarterly dividend of $0.06 per common share, payable on April 1, 2025.

On Feb. 19, 2025, the Company declared a quarterly dividend of $0.065 per common share, payable on July 1, 2025.

There have been no transactions involving common shares between the reporting date and the date of completion of these Consolidated Financial Statements.

29. Preferred Shares

A. Issued and Outstanding

All preferred shares issued and outstanding are non-voting cumulative redeemable fixed or floating rate first preferred shares.

As at Dec. 31	2024		2023	
Series[1]	Number of shares (millions)	Amount	Number of shares (millions)	Amount
Series A	**9.6**	**235**	9.6	235
Series B	**2.4**	**58**	2.4	58
Series C	**10.0**	**243**	10.0	243
Series D	**1.0**	**26**	1.0	26
Series E	**9.0**	**219**	9.0	219
Series G	**6.6**	**161**	6.6	161
Issued and outstanding, end of period	**38.6**	**942**	38.6	942

(1) The Series I Preferred Shares are accounted for as long-term debt. Refer to Note 26.

Series G Cumulative Redeemable Rate Reset Preferred Shares

During the third quarter of 2024, after taking into account all election notices received for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series G (Series G shares), 20,607 Series G shares out of 6.6 million outstanding, were tendered for conversion, which is less than the 1 million shares required to give effect to conversion into Series H shares. As a result, none of the Series G Shares were converted into Series H Shares on Sept. 30, 2024 and the next conversion date was reset to Sept. 30, 2029.

Preferred Share Series Information

The holders are entitled to receive cumulative fixed quarterly cash dividends at specified rates, as approved by the Board. After an initial period of approximately five years from issuance and every five years thereafter (Rate Reset Date), the fixed rate resets to the sum of the five-year Government of Canada bond yield (the fixed rate Benchmark) plus a specified spread. Upon each Rate Reset Date, the shares are also:

- Redeemable at the option of the Company, in whole or in part, for $25.00 per share, plus all declared and unpaid dividends at the time of redemption.
- Convertible at the holder's option into a specified series of non-voting cumulative redeemable floating rate first preferred shares that pay cumulative floating rate quarterly cash dividends, as approved by the Board, based on the sum of the Government of Canada 90-day Treasury Bill rate (the floating rate Benchmark) plus a specified spread. The cumulative floating rate first preferred shares are also redeemable at the option of the Company and convertible back into each original cumulative fixed rate first preferred share series, at each subsequent Rate Reset Date, on the same terms as noted above.

Characteristics specific to each first preferred share series as at Dec. 31, 2024, are as follows:

Series[1]	Rate during term	Annual dividend rate per share ($)[2]	Next conversion date	Rate spread over benchmark (per cent)	Convertible to Series
A	Fixed	0.71924	March 31, 2026	2.03	B
B	Floating	1.60106	March 31, 2026	2.03	A
C	Fixed	1.46352	June 30, 2027	3.10	D
D	Floating	1.86801	June 30, 2027	3.10	C
E	Fixed	1.72352	Sept. 30, 2027	3.65	F
G	Fixed	1.47012	Sept. 30, 2029	3.80	H

(1) The Series I Preferred Shares are accounted for as long-term debt. Refer to Note 26.

(2) The annual dividend rate per share represents dividends declared in 2024.

B. Dividends

The following table summarizes the preferred share dividends declared in 2024 and 2023:

	Total dividends declared	
Series	2024	2023
A	**7**	7
B[1]	**4**	4
C	**15**	15
D[2]	**2**	2
E	**15**	15
G	**9**	8
Total for the year	**52**	51

(1) Series B Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 2.03 per cent.

(2) Series D Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 3.10 per cent.

On Dec. 9, 2024, the Company declared a quarterly dividend of $0.17981 per share on the Series A preferred shares, $0.33972 per share on the Series B preferred shares, $0.36588 per share on the Series C preferred shares, $0.40568 per share on the Series D preferred shares, $0.43088 per share on the Series E preferred shares and $0.42331 per share on the Series G preferred shares, payable on March 31, 2025.

30. Accumulated Other Comprehensive Income (Loss)

The components of and changes in, accumulated other comprehensive loss are as follows:

	2024	2023
Currency translation adjustment		
Opening balance, Jan. 1	**(36)**	(39)
Gains (losses) on translating net assets of foreign operations, net of reclassifications to net earnings, net of tax	**30**	(6)
(Losses) gains on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax[1]	**(28)**	9
Balance, Dec. 31	**(34)**	(36)
Cash flow hedges		
Opening balance, Jan. 1	**(129)**	(228)
Gains on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax[2]	**194**	99
Balance, Dec. 31	**65**	(129)
Employee future benefits		
Opening balance, Jan. 1	**3**	8
Net actuarial gains (losses) on defined benefit plans, net of tax[3]	**9**	(5)
Balance, Dec. 31	**12**	3
Other		
Opening balance, Jan. 1	**(2)**	37
Change in ownership of TransAlta Renewables	**—**	(64)
Intercompany and third-party investments at FVTOCI	**—**	25
Balance, Dec. 31	**(2)**	(2)
Accumulated other comprehensive income (loss)	**41**	(164)

(1) Net of income tax recovery of $4 million for the year ended Dec. 31, 2024 (Dec. 31, 2023 – $1 million expense).

(2) Net of income tax expense of $53 million for the year ended Dec. 31, 2024 (Dec. 31, 2023 – $27 mil ion).

(3) Net of income tax expense of $3 million for the year ended Dec. 31, 2024 (Dec. 31, 2023 – $1 million recovery).

31. Share-Based Payment Plans

The Company has the following share-based payment plans:

A. Performance Share Unit (PSU) and Restricted Share Unit (RSU) Plan

Under the Share Unit Plan, grants of PSUs and RSUs may be made annually, but are measured and assessed over a three-year performance period. Grants are determined as a percentage of participants' base pay and are converted to PSUs or RSUs on the basis of the Company's common share price at the time of grant. Vesting of PSUs is subject to achievement over a three-year period of specific performance measures that are established at the time of each grant. RSUs are subject to a three-year cliff-vesting requirement. RSUs and PSUs track the Company's share price over the three-year period and accrue dividends as additional units at the same rate as dividends paid on the Company's common shares.

The pre-tax compensation expense related to PSUs and RSUs in 2024 was $23 million (2023 — $21 million, 2022 — $20 million), which is included in OM&A in the Consolidated Statements of Earnings.

B. Deferred Share Unit (DSU) Plan

Under the Share Unit Plan, members of the Board and executives may, at their option, purchase DSUs using certain components of their fees or pay. A DSU is a notional share that has the same value as one common share of the Company and fluctuates based on the changes in the value of the Company's common shares in the marketplace. DSUs accrue dividends as additional DSUs at the same rate as dividends are paid on the Company's common shares. DSUs are redeemable in cash and may not be redeemed until the termination or retirement of the director or executive from the Company.

The Company accrues a liability and expense for the appreciation in the common share value in excess of the DSU's purchase price and for dividend equivalents earned.

The pre-tax compensation expense related to the DSUs was $8 million in 2024 (2023 — $1 million, 2022 — nil).

C. Stock Option Plan

In 2024, the Company granted executive officers of the Company a total of 0.7 million stock options with a weighted average exercise price of $10.88 that vest over a three-year period and expire seven years after issuance (2023 — 0.4 million stock options at $12.02; 2022 — 0.3 million stock options at $12.66). The expense recognized relating to these grants during 2024 was approximately $1 million (2023 — approximately $1 million, 2022 — approximately $1 million).

The total options outstanding and exercisable under the Stock Option Plan at Dec. 31, 2024, are outlined below:

	Options outstanding		
Range of exercise prices ($ per share)	**Number of options (millions)[1]**	**Weighted average remaining contractual life (years)**	**Weighted average exercise price ($ per share)**
9.28-12.67	**1.6**	**4.67**	**10.97**

(1) Includes 0.7 million options exercisable as at Dec. 31, 2024.

32. Employee Future Benefits

A. Description

The Company sponsors registered pension plans in Canada and the U.S. covering substantially all employees of the Company in both countries and specific named employees working internationally. These plans have defined benefit and defined contribution options and in Canada there is an additional non-registered supplemental plan for eligible employees whose annual earnings exceed the Canadian income tax limit. Except for the Highvale pension plan acquired in 2013, the Canadian and U.S. defined benefit pension plans are closed to new entrants. The U.S. defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned. The supplemental pension plan was closed as of Dec. 31, 2015, and a new defined contribution supplemental pension plan commenced for executive members effective Jan. 1, 2016. Current executives as of Dec. 31, 2015, were grandfathered into the old supplemental plan.

The Company's U.S. defined benefit pension plan was terminated effective June 30, 2024 and annuitized in October 2024.

The latest actuarial valuation for accounting purposes of the U.S. defined benefit pension plan was at Jan. 1, 2023. The latest actuarial valuation for accounting purposes of the Highvale pension plan was at Dec. 31, 2022. The latest actuarial valuation for accounting purposes of the Registered Supplemental, and Other Canadian pension plans were at Dec. 31, 2021, Dec. 31, 2022 and Dec. 31, 2023, respectively. The measurement date used for all plans to determine the fair value of plan assets and the present value of the defined benefit obligation was Dec. 31, 2024.

Funding of the registered pension plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, or more, depending on funding status and every year in the U.S.. The supplemental pension plan is solely the obligation of the Company. The Company is not obligated to fund the supplemental plan but is obligated to pay benefits under the terms of the plan as they come due. The Company posted a letter of credit in March 2024 in the amount of $90 million, and provided $62 million in surety bonds, to secure the obligations under the supplemental plan and the Canadian defined benefit plan, respectively.

The Company provides other health and dental benefits to certain eligible employees to the age of 65 for both disabled members and retired members through its other post-employment benefits plans. The measurement date used to determine the present value obligation for both plans was Dec. 31, 2024.

The Company provides several defined contribution plans, including the acquired Heartland plan, an Australian superannuation plan and a U.S. 401(k) savings plan, that provide for company contributions from five to 11.5 per cent, depending on the plan.

Optional employee contributions are allowed for all the defined contribution plans.

B. Costs Recognized

The costs recognized in net earnings during the year on the defined benefit, defined contribution and other post-employment benefits plans are as follows:

Year ended Dec. 31, 2024	Registered	Supplemental	Other	Total
Current service cost	**1**	**1**	**1**	**3**
Administration expenses	**1**	**—**	**—**	**1**
Interest cost on defined benefit obligation	**14**	**4**	**1**	**19**
Interest on plan assets	**(12)**	**(1)**	**—**	**(13)**
Defined benefit expense	**4**	**4**	**2**	**10**
Defined contribution expense	**12**	**—**	**—**	**12**
Net expense	**16**	**4**	**2**	**22**

Year ended Dec. 31, 2023	Registered	Supplemental	Other	Total
Current service cost	1	1	—	2
Administration expenses	1	—	—	1
Interest cost on defined benefit obligation	16	4	1	21
Interest on plan assets	(13)	(1)	—	(14)
Defined benefit expense	5	4	1	10
Defined contribution expense	11	—	—	11
Net expense	16	4	1	21

Year ended Dec. 31, 2022	Registered	Supplemental	Other	Total
Current service cost	1	1	—	2
Administration expenses	1	—	—	1
Interest cost on defined benefit obligation	13	3	—	16
Interest on plan assets	(9)	—	—	(9)
Defined benefit expense	6	4	—	10
Defined contribution expense	11	—	—	11
Net expense	17	4	—	21

C. Status of Plans

The status of the defined benefit pension and other post-employment benefit plans is as follows:

Year ended Dec. 31, 2024	Registered	Supplemental	Other	Total
Fair value of plan assets	**241**	**16**	**—**	**257**
Present value of defined benefit obligation	**(303)**	**(90)**	**(18)**	**(411)**
Funded status – plan deficit	**(62)**	**(74)**	**(18)**	**(154)**
Amount recognized in the Consolidated Financial Statements:				
Accrued current liabilities	**(1)**	**(6)**	**(1)**	**(8)**
Other long-term liabilities	**(61)**	**(68)**	**(17)**	**(146)**
Total amount recognized	**(62)**	**(74)**	**(18)**	**(154)**

Year ended Dec. 31, 2023	Registered	Supplemental	Other	Total
Fair value of plan assets	269	15	—	284
Present value of defined benefit obligation	(340)	(89)	(17)	(446)
Funded status – plan deficit	(71)	(74)	(17)	(162)
Amount recognized in the Consolidated Financial Statements:				
Accrued current liabilities	(1)	(5)	(1)	(7)
Other long-term liabilities	(70)	(69)	(16)	(155)
Total amount recognized	(71)	(74)	(17)	(162)

D. Plan Assets

The fair value of the plan assets of the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	Supplemental	Other	Total
As at Dec. 31, 2022	274	15	—	289
Interest on plan assets	13	1	—	14
Net return on plan assets	15	(1)	—	14
Contributions[1]	5	6	2	13
Benefits paid	(36)	(6)	(2)	(44)
Administration expenses	(1)	—	—	(1)
Change in foreign exchange rates	(1)	—	—	(1)
As at Dec. 31, 2023	269	15	—	284
Interest on plan assets	**12**	**1**	**—**	**13**
Net return on plan assets	**13**	**(1)**	**—**	**12**
Contributions	**1**	**6**	**1**	**8**
Benefits paid	**(31)**	**(5)**	**(1)**	**(37)**
Administration expenses	**(1)**	**—**	**—**	**(1)**
Effect of settlement from annuitization of the U.S. defined benefit plan (Note 27)	**(23)**	**—**	**—**	**(23)**
Change in foreign exchange rates	**1**	**—**	**—**	**1**
As at Dec. 31, 2024	**241**	**16**	**—**	**257**

(1) The Company made a voluntary contribution of nil (2023 — $4 million) to further improve the funded status of the U.S. defined benefit pension plan for the Centra ia thermal facility.

The fair value of the Company's defined benefit plan assets by major category is as follows:

As at Dec. 31, 2024	Level I	Level II	Level III	Total
Equity securities				
Canadian	—	12	—	12
International	—	53	—	53
Private	—	—	1	1
Bonds				
A - AAA	—	18	81	99
BBB	—	1	16	17
Below BBB	—	—	5	5
Loans[1]	—	1	—	1
Other				
Alternative funds[2]	—	—	46	46
Money market and cash and cash equivalents	2	19	2	23
Total	2	104	151	257

(1) Includes A credit rating loans of $1 million.

(2) Alternative funds include investments in infrastructure and real estate funds.

As at Dec. 31, 2023	Level I	Level II	Level III	Total
Equity securities				
Canadian	—	12	—	12
U.S.	—	6	—	6
International	—	86	—	86
Private	—	—	1	1
Bonds				
A - AAA	—	30	62	92
BBB	1	5	10	16
Below BBB	—	—	4	4
Loans[1]	—	2	—	2
Other				
Alternative funds[2]	—	—	44	44
Money market and cash and cash equivalents	2	19	—	21
Total	3	160	121	284

(1) Includes A credit rating loans of $1 million.

(2) Alternative funds include investments in infrastructure and real estate funds.

Plan assets do not include any common shares of the Company at Dec. 31, 2024 and Dec. 31, 2023.

E. Defined Benefit Obligation

The present value of the obligation for the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	Supplemental	Other	Total
Present value of defined benefit obligation as at Dec. 31, 2022	345	85	17	447
Current service cost	1	1	—	2
Interest cost	16	4	1	21
Benefits paid	(36)	(6)	(2)	(44)
Actuarial gain arising from demographic assumptions	1	—	—	1
Actuarial gain arising from financial assumptions	12	4	1	17
Actuarial gain arising from experience adjustments	2	1	—	3
Change in foreign exchange rates	(1)	—	—	(1)
Present value of defined benefit obligation as at Dec. 31, 2023	340	89	17	446
Current service cost	**1**	**—**	**1**	**2**
Interest cost	**14**	**4**	**1**	**19**
Benefits paid	**(31)**	**(5)**	**(1)**	**(37)**
Actuarial gain arising from financial assumptions	**1**	**1**	**—**	**2**
Actuarial gain arising from experience adjustments	**—**	**1**	**—**	**1**
Effect of settlement from the termination of the U.S. defined benefit plan (Note 27)	**(23)**	**—**	**—**	**(23)**
Change in foreign exchange rates	**1**	**—**	**—**	**1**
Present value of defined benefit obligation as at Dec. 31, 2024[1]	**303**	**90**	**18**	**411**

(1) The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2024, is 9.8 years.

F. Contributions

The expected employer contributions for 2025 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	**1**	**6**	**1**	**8**

G. Assumptions

The significant actuarial assumptions used in measuring the Company's defined benefit obligation for the defined benefit pension and other post-employment benefit plans are as follows:

	2024			2023		
As at Dec. 31 (per cent)	**Registered**	**Supplemental**	**Other**	**Registered**	**Supplemental**	**Other**
Accrued benefit obligation						
Discount rate	**4.5**	**4.5**	**4.8**	4.6	4.6	4.7
Rate of compensation increase	**2.9**	**3.0**	**—**	2.9	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation[1][3]	**—**	**—**	**6.7**	—	—	6.8
Dental-care cost escalation	**—**	**—**	**4.1**	—	—	4.2
Benefit cost for the year						
Discount rate	**4.6**	**4.6**	**4.7**	5.0	5.0	5.0
Rate of compensation increase	**2.9**	**3.0**	**—**	2.7	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation[2][4]	**—**	**—**	**6.7**	—	—	7.1
Dental-care cost escalation	**—**	**—**	**4.6**	—	—	4.7

(1) 2024 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2034 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.

(2) 2024 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2033 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.

(3) 2023 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2033 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.

(4) 2023 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2032 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.

H. Sensitivity Analysis

The following table outlines the estimated increase in the net defined benefit obligation assuming certain changes in key assumptions:

	Canadian plans			U.S. plans
As at Dec. 31, 2024	**Registered**	**Supplemental**	**Other**	**Pension**
1% decrease in the discount rate	**28**	**10**	**1**	**—**
1% increase in the salary scale	**1**	**—**	**—**	**—**
1% increase in the health-care cost trend rate	**—**	**—**	**2**	**—**
10% improvement in mortality rates	**14**	**3**	**—**	**—**

33. Joint Arrangements

Joint arrangements at Dec. 31, 2024, included the following:

Joint operations	Segment	Ownership (per cent)	Description
Goldfields Power	Gas	50	Gas-fired facility in Western Australia operated by TransAlta
Fort Saskatchewan	Gas	60	Cogeneration facility in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
Fortescue River Gas Pipeline	Gas	43	Natural gas pipeline in Western Australia, operated by DBP Development Group
McBride Lake	Wind and Solar	50	Wind generation facility in Alberta operated by TransAlta
Soderglen	Wind and Solar	50	Wind generation facility in Alberta operated by TransAlta
Pingston	Hydro	50	Hydro facility in British Columbia operated by TransAlta
Joffre[(1)]	Gas	40	Cogeneration plant in Alberta operated by TransAlta
McMahon[(1)]	Gas	50	Cogeneration plant in British Columbia operated by TransAlta
Primrose[(1)]	Gas	50	Cogeneration plant in Alberta operated by TransAlta
Rainbow Lake[(1)(2)]	Gas	50	Cogeneration plant in Alberta operated by TransAlta

[(1)]The Company holds interest through its acquisition of Heartland. Refer to Note 4.

[(2)]The Company agreed to divest its interest in the Rainbow Lake facility to meet the requirements of the federal Competition Bureau, following the closing of the acquisition. As at Dec. 31, 2024 the Rainbow Lake facility is classified as part of a disposal group held for sale. Refer to Note 18.

Joint venture	Segment	Ownership (per cent)	Description
Skookumchuck	Wind and Solar	49	Wind generation facility in Washington operated by Southern Power
Tent Mountain	Hydro	60	Pumped hydro energy storage development project in Alberta

On Dec. 4, 2024, the Company acquired Heartland's 50 per cent interest in Sheerness, a natural-gas-fired facility in Alberta, previously operated by Heartland. Refer to Note 4 for details. On Oct. 8, 2024, the Company increased its interest by an additional 10 per cent interest in Tent Mountain. Refer to Note 9 for details.

34. Cash Flow Information

A. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	2024	2023	2022
Source (use):			
Accounts receivable	**155**	715	(869)
Prepaid expenses	**85**	—	—
Income taxes receivable	**22**	27	(61)
Inventory	**34**	(2)	6
Accounts payable, accrued liabilities and provisions	**(273)**	(550)	548
Income taxes payable	**15**	(66)	60
Change in non-cash operating working capital	**38**	124	(316)

B. Changes in Liabilities from Financing Activities

	Balance Dec. 31, 2023	Debt assumed	Repayments and dividends paid[1]	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2024
Long-term debt and lease liabilities[2]	3,469	**232**	**6**	**5**	**—**	**86**	**11**	**3,809**
Exchangeable securities	744	**—**	**—**	**—**	**—**	**—**	**6**	**750**
Dividends payable (common and preferred)	49	**—**	**(123)**	**—**	**123**	**—**	**—**	**49**
Total liabilities from financing activities	4,262	**232**	**(117)**	**5**	**123**	**86**	**17**	**4,608**

(1) Includes a decrease of $131 million related to the repayment of long-term debt, a $143 mil ion net decrease in borrowings under credit facilities and a decrease in finance lease obligations of $6 million.

(2) Includes bank overdraft of $1 mil ion and new debt assumed of $232 mil ion as part of the Heartland acquisition. Refer to Note 4.

	Balance Dec. 31, 2022	Cash issuances	Repayments and dividends paid[1]	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2023
Long-term debt and lease liabilities[2]	3,669	39	(220)	5	—	(36)	12	3,469
Exchangeable securities	739	—	—	—	—	—	5	744
Dividends payable (common and preferred)[3]	68	—	(109)	—	116	—	(26)	49
Total liabilities from financing activities	4,476	39	(329)	5	116	(36)	(9)	4,262

(1) Includes a decrease of $164 mil ion related to the repayment of long-term debt, a $46 mil ion net decrease in borrowings under credit faci ities and a decrease in finance lease obligations of $10 mil ion.

(2) Includes bank overdraft of $3 million.

(3) Other dividends payable related to payment of TransAlta Renewables' non-controlling interest dividend reflected within distributions paid to subsidiaries of non-control ing interests in the Consolidated Statements of Cash Flows.

35. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2024	2023	Increase/ (decrease)
Long-term debt[1]	**3,808**	3,466	**342**
Exchangeable securities	**750**	744	**6**
Bank overdraft	**1**	3	**(2)**
Equity			
Common shares	**3,179**	3,285	**(106)**
Preferred shares	**942**	942	**—**
Contributed surplus	**42**	41	**1**
Deficit	**(2,458)**	(2,567)	**109**
Accumulated other comprehensive income (loss)	**41**	(164)	**205**
Non-controlling interests	**97**	127	**(30)**
Less: Available cash and cash equivalents[2]	**(337)**	(348)	**11**
Less: Principal portion of restricted cash on TransAlta OCP bonds[3]	**(17)**	(17)	**—**
Less: Fair value (asset) liability of hedging instruments on long-term debt[4]	**(7)**	5	**(12)**
Total capital	**6,041**	5,517	**524**

(1) Includes lease liabilities, amounts outstanding under credit faci ities, tax equity liabilities, current portion of long-term debt and new debt assumed as part of the Heartland acquisition. Refer to Note 4.

(2) The Company includes available cash and cash equivalents, as a reduction in the calculation of capital, as capital is managed using a net debt position. These funds may be available and used to facilitate repayment of debt.

(3) The Company includes the principal portion of restricted cash on TransAlta OCP bonds as this cash is restricted specifically to repay outstanding debt.

(4) The Company includes the fair value of economic and designated hedging instruments on debt in an asset, or liability, position as a reduction, or increase, in the calculation of capital, as the carrying value of the related debt has either increased, or decreased, due to changes in foreign exchange rates.

The Company's overall capital management strategy and its objectives in managing capital are as follows:

A. Maintain a Strong Financial Position

The Company operates in a long-cycle and capital-intensive commodity business and it is therefore a priority to maintain a strong financial position that enables the Company to access capital markets at reasonable interest rates. Maintaining a strong balance sheet also allows our commercial team to contract the Company's portfolio with a variety of counterparties on terms and prices that are favourable to the Company's financial results and provides the Company with better access to capital markets through commodity and credit cycles. The Company has an investment grade credit rating from Morningstar DBRS. In 2024, Moody's reaffirmed the Company's long-term rating of Ba1 with a stable outlook. Morningstar DBRS reaffirmed the Company's issuer rating and unsecured debt/medium-term notes rating of BBB (low) and the Company's preferred shares rating of Pfd-3 (low), all with stable outlooks, and S&P Global Ratings reaffirmed the Company's senior unsecured debt rating and issuer credit rating of BB+ with a stable outlook. The Company remains focused on maintaining a strong financial position and cash flow coverage ratios. Credit ratings provide information relating to the Company's financing costs, liquidity and operations and affect the Company's ability to obtain short and long-term financing and/or the cost of such financing. Management routinely monitors forecasted net earnings, cash flows, capital expenditures and scheduled repayment of debt with a goal of maintaining its credit ratings and to meet dividend and PP&E expenditure requirements.

B. Liquidity

The Company manages variations in working capital using existing liquidity under credit facilities to ensure sufficient cash and credit are available to fund operations, pay dividends, distribute payments to subsidiaries' non-controlling interests and invest in PP&E.

For the years ended Dec. 31, 2024 and 2023, cash inflows and outflows are summarized below.

Year ended Dec. 31	2024	2023	Increase (decrease)
Cash flow from operating activities	**796**	1,464	**(668)**
Change in non-cash working capital	**(38)**	(124)	**86**
Cash flow from operations before changes in working capital	**758**	1,340	**(582)**
Dividends paid on common shares	**(71)**	(58)	**(13)**
Dividends paid on preferred shares	**(52)**	(51)	**(1)**
Distributions paid to subsidiaries' non-controlling interests	**(40)**	(223)	**183**
Property, plant and equipment expenditures	**(311)**	(875)	**564**
Inflow	**284**	133	**151**

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2024, $1.5 billion (2023 — $1.4 billion) of the Company's credit facilities were fully available.

From time to time, TransAlta accesses capital markets, as required, to help fund some of these periodic net cash outflows to maintain its available liquidity and maintain its capital structure and credit metrics within targeted ranges.

36. Related-Party Transactions

Details of the Company's principal operating subsidiaries at Dec. 31, 2024, are as follows:

Subsidiary	Country	Ownership (per cent)	Principal activity
TransAlta Generation Partnership	Canada	100	Generation and sale of electricity
TransAlta Cogeneration, L.P.	Canada	50.01	Generation and sale of electricity
TransAlta Centralia Generation, LLC	U.S.	100	Generation and sale of electricity
TransAlta Energy Marketing Corp.	Canada	100	Energy marketing
TransAlta Energy Marketing (U.S.), Inc.	U.S.	100	Energy marketing
TransAlta Energy (Australia), Pty Ltd.	Australia	100	Generation and sale of electricity
TransAlta Renewables Inc.	Canada	100	Generation and sale of electricity
Heartland Generation Ltd.	Canada	100[1]	Generation and sale of electricity
Alberta Power (2000) Ltd.	Canada	100[1]	Generation and sale of electricity

Associate or joint venture	Country	Ownership (per cent)	Principal activity
SP Skookumchuck Investment, LLC	U.S.	49	Generation and sale of electricity

(1) On Dec. 4, 2024, the Company completed the acquisition of Heartland. Refer to Note 4 for more details.

Transactions between the Company and its subsidiaries have been eliminated on consolidation and are not disclosed.

Associates and joint ventures have been equity accounted for by the Company.

A. Transactions with Key Management Personnel

TransAlta's key management personnel include the President and Chief Executive Officer (CEO), members of the senior management team that report directly to the President and CEO and the members of the Board. Key management personnel compensation is as follows:

Year ended Dec. 31	2024	2023	2022
Total compensation	**36**	21	23
Comprising:			
Short-term employee benefits	**13**	11	11
Post-employment benefits	**1**	1	1
Termination benefits	**4**	1	—
Share-based payments	**18**	8	11

B. Transactions with Associates

In connection with the exchangeable securities issued to Brookfield, the Investment Agreement entitles Brookfield to nominate two directors to the TransAlta Board. This allows Brookfield to participate in the financial and operating policy decisions of the Company, and as such, they are considered associates of the Company.

In addition to the exchangeable securities disclosed in Note 26, the Company may, in the normal course of operations, enter into transactions on market terms with associates that have been measured at exchange value and recognized in the Consolidated Financial Statements, including power purchase and sale agreements, derivative contracts and asset management fees. Transactions and balances between the Company and associates do not eliminate.

Transactions with Brookfield include the following:

Year ended Dec. 31	2024	2023	2022
Power sales	**58**	135	127
Purchased power	**4**	2	12
Asset management fees paid	**—**	1	2

37. Commitments and Contingencies

In addition to the commitments disclosed elsewhere in the financial statements, the Company has incurred the following contractual commitments, either directly or through its interests in joint operations and joint ventures.

Approximate future payments under these agreements are as follows:

	2025	2026	2027	2028	2029	2030 and thereafter	Total
Natural gas, transportation and other contracts	75	68	65	66	64	425	763
Transmission	23	23	21	10	8	105	190
Coal supply agreements	75	—	—	—	—	—	75
Long-term service agreements	61	47	50	31	18	151	358
Operating leases	4	3	3	2	2	22	36
Growth	46	3	—	—	—	—	49
Total	**284**	**144**	**139**	**109**	**92**	**703**	**1,471**

Commitments

Natural Gas, Transportation and Other Contracts

The Company has natural gas transportation contracts, for a total of up to 400 terajoules (TJ) per day on a firm basis, related to the Sundance and Keephills facilities, ending in 2036 to 2038. In addition, the Company has natural gas transportation agreements for approximately 150 TJ per day for Sheerness. The Company currently expects to use approximately 160TJ per day on average and up to approximately 450TJ per day during peak periods, while remarketing excess capacity.

Transmission

The Company has several agreements to purchase transmission network capacity in the Pacific Northwest. Provided certain conditions for delivering the service are met, the Company is committed to the transmission at the supplier's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed.

Transmission commitments also include multi-year U.S. dollar denominated contracts to secure transmission capacity. The majority of the transmission capacity supports a dedicated revenue capacity agreement, held with a counterparty in the U.S., for similar duration as the associated transmission capacity.

Coal Supply Agreements

Various coal supply and associated rail transport contracts are in place to provide coal for use in production at the Centralia thermal facility. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes with dates extending through 2025.

Long-Term Service Agreements

TransAlta has various service agreements in place, primarily for inspections, repairs and maintenance that may be required on natural gas facilities, equipment for gas and turbines at various wind facilities.

Operating Leases

Operating leases include lease commitments not recognized under IFRS 16 and lease commitments that have not yet commenced, mainly related to buildings, vehicles and land.

Growth

Commitments for growth include design and engineering work, long lead equipment purchases, water treatment construction and network upgrades.

Contingencies

TransAlta is occasionally named as a party in various claims and legal and regulatory proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Company's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Company responds as required.

The Company conducts internal reviews of its offers and offer behaviour in both the energy and ancillary services markets in Alberta on an ongoing basis and will self-report suspected contraventions or respond to inquiries from regulatory agencies as required. There currently is no certainty that any particular matter will be resolved in the Company's favour or that such matters may not have a material adverse effect on TransAlta.

Brazeau Facility — Well Licence Applications to Consider Hydraulic Fracturing Activities

The Alberta Energy Regulator (AER) issued a subsurface order on May 27, 2019, which does not permit any hydraulic fracturing within three kilometres of the Brazeau facility, but permits hydraulic fracturing in all formations (except the Duvernay) within three to five kilometres of the Brazeau facility. Subsequently, two oil and gas operators submitted applications to the AER for 10 well licences (which include hydraulic fracturing activities) within three to five kilometres of the Brazeau facility.

The Company's position, based on independent expert analysis commissioned by the Government of Alberta, is that hydraulic fracturing activities within five kilometres of the Brazeau facility pose an unacceptable risk and that the applications should be denied. The regulatory hearing to consider these applications - Proceeding 379 - has been adjourned to November 2025.

Brazeau Facility — Claim against the Government of Alberta

On Sept. 9, 2022, the Company filed a Statement of Claim against the Government of Alberta in the Alberta Court of King's Bench seeking a declaration that: (a) granting mineral leases within five kilometres of the Brazeau facility is a breach of a 1960 agreement between the Company and the Alberta Government; and (b) the Government of Alberta is required to indemnify the Company for any costs or damages that result from the risks of hydraulic fracturing near the Brazeau facility. On Sept. 29, 2022, the Government of Alberta filed its Statement of Defence, which asserts, among other things, that the Company: (a) is trying to usurp the jurisdiction of the AER; and (b) is out of time under the Limitations Act (Alberta). The trial is scheduled to be heard in September or October 2025 in the event the parties are unable to resolve the dispute prior to such date.

Garden Plain

Garden Plain I LP, a wholly-owned subsidiary of the Company, retained a third-party contractor to construct the Garden Plain wind project near Hanna, Alberta. The contractor experienced scheduling delays, challenges with construction and significant cost overruns, resulting in overdue deadlines, and has asserted a claim for $53 million in damages. The Company disputes this claim in its entirety and asserts a counterclaim. The parties have initiated the dispute resolution procedure with an arbitration hearing scheduled for three weeks starting April 14, 2025.

Sundance A Decommissioning

TransAlta filed an application with the Alberta Utilities Commission seeking payment from the Balancing Pool for TransAlta's decommissioning costs for Sundance A, including its proportionate share of the Highvale mine. The application was heard by Alberta Utilities Commission in the first quarter of 2024. A decision was rendered on Dec. 9, 2024, which directed the Balancing Pool to pay TransAlta $9 million, being the shortfall of decommissioning costs of Sundance A from previously collected amounts under the Power Purchase Arrangement Regulation.

Brazeau — Spinning Reserve Self-Report

On Nov. 30, 2022, TransAlta self-reported to the Market Surveillance Administrator (MSA) a potential violation of the Independent System Operator rules relating to offers of active spinning reserves at Brazeau when it was not properly configured to do so between Aug. 13, 2021, and Nov. 1, 2022. In 2022 a provision of $20 million was initially recognized in revenue reflecting a potential disgorgement of revenue and $2 million for potential penalties and fines. On Nov. 29, 2024, the MSA issued penalties to TransAlta for this self-report and TransAlta made a payment of $33 million in January 2025.

38. Segment Disclosures

A. Description of Reportable Segments

The Company has six reportable segments as described in Note 1. The Gas reportable segment includes Heartland, which was acquired on Dec. 4, 2024. The Company has aggregated Heartland within the Gas operating segment as they are similar in the nature of the product and process and are subject to similar environmental regulations. Refer to Note 4 for more details.

The following tables provides each segment's results in the format that the TransAlta's President and Chief Executive Officer (the chief operating decision maker) (CODM) reviews the Company's segments to make operating decisions and assess performance. The CODM assesses the performance of the operating segments based on a measure of adjusted EBITDA. This measurement basis represents earnings before income taxes, adjusted for the effects of: depreciation of property, plant and equipment and amortization of intangibles, depreciation of right-of-use assets, finance lease income, unrealized mark-to-market gains or losses, gains and losses related to closed positions effectively settled by offsetting positions with exchanges recorded in the year the positions are settled, unrealized foreign exchange gains or losses on commodity transactions, interest income recorded on the prepaid funds, Brazeau penalties, acquisition-related transaction and restructuring costs, ERP integration costs, revenues and fuel and purchased power related to the Planned Divestitures, items within the Energy Transition segment that may not be reflective of ongoing operations including certain costs related to decisions made to accelerate our transition off-coal in Alberta and our planned transition off-coal for Centralia, Sundance A decommissioning costs reimbursement, impairment charges, share of (profit) loss of joint venture and other costs or income adjustments.

For internal reporting purpose, the earnings information from the Company's investment in Skookumchuck has been presented in the Wind and Solar segment on a proportionate basis. Information on a proportionate basis reflects the Company's share of Skookumchuck's statement of earnings on a line-by-line basis. Proportionate financial information is not and is not intended to be, presented in accordance with IFRS. Under IFRS, the investment in Skookumchuck has been accounted for as a joint venture using the equity method.

The tables below show the reconciliation of the total segmented results and adjusted EBITDA to the statement of earnings reported under IFRS.

B. Reported Adjusted Segment Earnings and Segment Assets

I. Reconciliation of Adjusted EBITDA to Earnings before Income Tax

Year ended Dec. 31, 2024	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	409	357	1,350	616	168	(34)	2,866	(21)	—	2,845
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	1	84	(60)	(36)	14	—	3	—	(3)	—
Realized gain (loss) on closed exchange positions	—	—	7	2	(15)	—	(6)	—	6	—
Decrease in finance lease receivable	—	2	19	—	—	—	21	—	(21)	—
Finance lease income	—	6	8	—	—	—	14	—	(14)	—
Revenues from Planned Divestitures	—	—	(1)	—	—	—	(1)	—	1	—
Brazeau penalties	(20)	—	—	—	—	—	(20)	—	20	—
Unrealized foreign exchange gain on commodity	—	—	(2)	—	—	—	(2)	—	2	—
Adjusted revenues	390	449	1,321	582	167	(34)	2,875	(21)	(9)	2,845
Fuel and purchased power	16	30	475	418	—	—	939	—	—	939
Reclassifications and adjustments:										
Fuel and purchased power related to Planned Divestitures	—	—	(1)	—	—	—	(1)	—	1	—
Austra ian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted fuel and purchased power	16	30	470	418	—	—	934	—	5	939
Carbon comp iance	—	—	145	1	—	(34)	112	—	—	112
Gross margin	374	419	706	163	167	—	1,829	(21)	(14)	1,794
OM&A	86	97	198	69	36	173	659	(4)	—	655
Reclassifications and adjustments:										
Brazeau penalties	(31)	—	—	—	—	—	(31)	—	31	—
ERP integration costs	—	—	—	—	—	(14)	(14)	—	14	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(24)	(24)		24	—
Adjusted OM&A	55	97	198	69	36	135	590	(4)	69	655
Taxes, other than income taxes	3	16	13	3	—	1	36	—	—	36
Net other operating income	—	(10)	(40)	(9)	—	—	(59)	—	—	(59)
Reclassifications and adjustments:										
Sundance A decommissioning cost	—	—	—	9	—	—	9	—	(9)	—
Adjusted net other operating income	—	(10)	(40)	—	—	—	(50)	—	(9)	(59)
Adjusted EBITDA[2]	316	316	535	91	131	(136)	1,253			
Equity income										5
Finance lease income										14
Depreciation and amortization										(531)
Asset impairment charges										(46)
Interest income										30
Interest expense										(324)
Foreign exchange gain										5
Gain on sale of assets and other										4
Earnings before income taxes										319

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA are not defined and have no standardized meaning under IFRS.

Year ended Dec. 31, 2023	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	533	357	1,514	751	220	1	3,376	(21)	—	3,355
Reclassifications and adjustments:										
Unrea ized mark-to-market (gain) loss	(4)	16	(67)	(5)	23	—	(37)	—	37	—
Rea ized gain (loss) on closed exchange positions	—	—	10	—	(91)	—	(81)	—	81	—
Decrease in finance lease receivable	—	—	55	—	—	—	55	—	(55)	—
Finance lease income	—	—	12	—	—	—	12	—	(12)	—
Unrea ized foreign exchange gain on commodity	—	—	1	—	—	—	1	—	(1)	—
Adjusted revenues	529	373	1,525	746	152	1	3,326	(21)	50	3,355
Fuel and purchased power	19	30	453	557	—	1	1,060	—	—	1,060
Reclassifications and adjustments:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted fuel and purchased power	19	30	449	557	—	1	1,056	—	4	1,060
Carbon compliance	—	—	112	—	—	—	112	—	—	112
Gross margin	510	343	964	189	152	—	2,158	(21)	46	2,183
OM&A	48	80	192	64	43	115	542	(3)	—	539
Taxes, other than income taxes	3	12	11	3	—	1	30	(1)	—	29
Net other operating income	—	(7)	(40)	—	—	—	(47)		—	(47)
Reclassifications and adjustments:										
Insurance recovery	—	1	—	—	—	—	1	—	(1)	—
Adjusted net other operating income	—	(6)	(40)	—	—	—	(46)	—	(1)	(47)
Adjusted EBITDA[2]	459	257	801	122	109	(116)	1,632			
Equity income										4
Finance lease income										12
Depreciation and amortization										(621)
Asset impairment charges										48
Interest income										59
Interest expense										(281)
Foreign exchange gain										(7)
Gain on sale of assets and other										4
Earnings before income taxes										880

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

Year ended Dec. 31, 2022	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	606	303	1,209	714	160	(2)	2,990	(14)		2,976
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	1	104	251	10	12	—	378	—	(378)	—
Realized gain (loss) on closed exchange positions	—	—	(4)	—	47	—	43	—	(43)	—
Decrease in finance lease receivable	—	—	46	—	—	—	46	—	(46)	—
Finance lease income	—	—	19	—	—	—	19	—	(19)	—
Brazeau penalties	20	—	—	—	—	—	20	—	(20)	—
Unrealized foreign exchange gain on commodity	—	—	—	—	(1)	—	(1)	—	1	—
Adjusted revenues	627	407	1,521	724	218	(2)	3,495	(14)	(505)	2,976
Fuel and purchased power	22	31	641	566	—	3	1,263	—	—	1,263
Reclassifications and adjustments:										
Austra ian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted fuel and purchased power	22	31	637	566	—	3	1,259	—	4	1,263
Carbon comp iance	—	1	83	(1)	—	(5)	78	—	—	78
Gross margin	605	375	801	159	218	—	2,158	(14)	(509)	1,635
OM&A	55	68	195	69	35	101	523	(2)	—	521
Reclassifications and adjustments:										
Brazeau penalties	(2)	—	—	—	—	—	(2)	—	2	—
Adjusted OM&A	53	68	195	69	35	101	521	(2)	2	521
Taxes, other than income taxes	3	12	15	4	—	1	35	(2)	—	33
Net other operating loss (income)	—	(23)	(38)	—	—	—	(61)	3	—	(58)
Reclassifications and adjustments:										
Royalty onerous contract and contract termination penalties	—	7	—	—	—	—	7	—	(7)	—
Adjusted net other operating loss (income)	—	(16)	(38)	—	—	—	(54)	3	(7)	(58)
Adjusted EBITDA[2]	549	311	629	86	183	(102)	1,656			
Equity income										9
Finance lease income										19
Depreciation and amortization										(599)
Asset impairment charges										(9)
Interest income										24
Interest expense										(286)
Foreign exchange gain										4
Gain on sale of assets and other										52
Earnings before income taxes										353

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2024	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
PP&E	501	3,428	1,805	206	—	80	6,020
Right-of-use assets	7	96	6	—	—	11	120
Intangible assets	3	133	108	4	3	30	281
Goodwill	258	178	51	—	30	—	517

As at Dec. 31, 2023	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
PP&E	462	3,360	1,543	251	—	98	5,714
Right-of-use assets	7	94	5	—	—	11	117
Intangible assets	2	141	40	4	5	31	223
Goodwill	258	176	—	—	30	—	464

III. Selected Consolidated Statements of Cash Flows Information

Additions to non-current assets are as follows:

Year ended Dec. 31, 2024	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Additions to non-current assets:							
PP&E[1]	64	97	100	13	—	37	311
Intangible assets[1]	—	—	—	—	—	10	10

[1]Excludes additions attributable to the Heartland acquisition on Dec. 4, 2024

Year ended Dec. 31, 2023	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Additions to non-current assets:							
PP&E	42	674	89	16	—	54	875
Intangible assets	—	—	—	—	—	13	13

Year ended Dec. 31, 2022	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Additions to non-current assets:							
PP&E	36	745	43	19	—	75	918
Intangible assets	—	19	—	—	3	9	31

C. Geographic Information

I. Revenues

Year ended Dec. 31	2024	2023	2022
Canada	**2,009**	2,218	1,905
U.S.	**676**	987	940
Western Australia	**160**	150	131
Total revenue	**2,845**	3,355	2,976

II. Non-Current Assets

	Property, plant and equipment		Right-of-use assets		Intangible assets		Other assets	
As at Dec. 31	2024	2023	2024	2023	2024	2023	2024	2023
Canada	**3,828**	3,578	**41**	43	**170**	108	**85**	68
U.S.	**1,852**	1,749	**74**	71	**86**	88	**36**	42
Western Australia	**340**	387	**5**	3	**25**	27	**58**	69
Total	**6,020**	5,714	**120**	117	**281**	223	**179**	179

D. Significant Customer

For the year ended Dec. 31, 2024, sales to the Alberta Electric System Operator represented 24 per cent of the Company's total revenue (2023 — 46 per cent of the Company's total revenue). There were no other companies that accounted for more than 10 per cent of the Company's total revenue.

Eleven-Year Financial and Statistical Summary

(in millions of Canadian dollars, except where noted)

Year ended Dec. 31	2024	2023	2022
Financial Summary			
STATEMENT OF EARNINGS			
Revenues	**2,845**	3,355	2,976
Operating income (loss)	**585**	1089	531
Earnings (loss) before income taxes	**319**	880	353
Net earnings (loss) attributable to common shareholders	**177**	644	4
STATEMENT OF FINANCIAL POSITION			
Total assets	**9,499**	8,659	10,741
Current portion of long-term debt, net of cash and cash equivalents	**235**	184	(940)
Credit facilities, long-term debt and finance lease obligations	**3,236**	2,934	3,475
Exchangeable securities	**750**	744	739
Non-controlling interests	**97**	127	879
Preferred shares	**942**	942	942
Equity attributable to common shareholders[1]	**804**	595	168
Principal portion of restricted cash on TransAlta OCP and fair value (asset) iabi ity of hedging instruments on debt[1]	**(24)**	(12)	(20)
Total capital[3]	**6,041**	5,517	5,243
CASH FLOWS			
Cash flow from operating activities	**796**	1,464	877
Cash flow used in investing activities	**(520)**	(814)	(741)
COMMON SHARE INFORMATION (per share)			
Net earnings	**0.59**	2.33	0.01
Comparable earnings[1]	**n/a**	n/a	n/a
Dividends declared on common share	**0.24**	0.22	0.21
Book value per common share (at year-end)[1]	**2.66**	2.16	0.62
Market price:			
High	**20.55**	13.97	15.28
Low	**8.35**	10.02	10.52
Close (Toronto Stock Exchange at Dec. 31)	**20.33**	11.02	12.11
RATIOS (percentage except where noted)			
Adjusted net debt to adjusted EBITDA[1,2,4,5] (times)	**3.6**	2.5	2.1
Return on equity attributable to common shareholders[1]	**23.2**	84.8	1.0
Comparable return on equity attributable to common shareholders[1]	**n/a**	n/a	n/a
Return on capital employed[1]	**10.0**	17.6	9.2
Comparable return on capital employed[1]	**n/a**	n/a	n/a
Earnings coverage (times)[1]	**2.2**	4.3	2.2
Dividend payout ratio based on FFO[1,5]	**9.2**	4.4	4.1
Adjusted EBITDA[1,2,4,5] (in mil ions of Canadian dollars)	**1,253**	1,632	1,656
Dividend coverage[1,5] (times)	**11.2**	24.6	18.3
Dividend yield[1]	**1.1**	2.0	1.7
Weighted average common shares for the year (in mil ions)	**302**	276	271
Common shares outstanding at Dec. 31 (in mil ions)	**298**	307	268
STATISTICAL SUMMARY			
Number of employees	**1,205**	1,257	1,282
GROSS INSTALLED CAPACITY (MW)[6]			
Energy Transition[8]	**671**	671	671
Gas[7,9]	**4,834**	3,084	3,084
Renewables (wind, solar and hydro)	**3,509**	3,006	2,828
Equity investments	**67**	67	67
Total generating capacity	**9,081**	6,828	6,650
Total production (GWh)	**22,811**	22,029	21,258

Financial data presented is based on IFRS. Prior year figures that appear within the MD&A have been restated to conform with the current year's presentation. All other prior year figures have not been restated.

(1) These items are not defined and have no standardized meaning under IFRS. Periods for which the non-IFRS measure was not previously disclosed have not been calculated. After 2016, comparable earnings measures are no longer being calculated or reported on.

2021	2020	2019	2018	2017	2016	2015	2014
2,721	2,101	2,347	2,249	2,307	2,397	2,267	2,623
(239)	(99)	335	160	138	478	148	442
(380)	(303)	193	(96)	(54)	314	221	239
(576)	(336)	52	(248)	(190)	117	(24)	141
9,226	9,747	9,508	9,428	10,304	10,996	10,947	9,833
(103)	(598)	102	59	433	334	33	708
2,423	3,256	2,699	3,119	2,960	3,722	4,408	3,305
735	730	326	—	—	—	—	—
1,011	1,084	1,101	1,137	1,059	1,152	1,029	594
942	942	942	942	942	942	942	942
640	1,410	2,019	2,055	2,384	2,569	2,419	2,342
(19)	(13)	(17)	(10)	(30)	(163)	(190)	(96)
5,629	6,811	7,172	7,275	7,748	8,556	8,641	7,795
1001	702	849	820	626	744	432	796
(472)	(687)	(512)	(394)	87	(327)	(573)	(292)
(2.13)	(1.22)	0.18	(0.86)	(0.66)	0.41	(0.09)	0.52
n/a	n/a	n/a	n/a	n/a	0.13	(0.17)	0.25
0.19	0.22	0.12	0.2	0.16	0.3	0.72	0.83
2.37	5.13	7.14	7.16	8.28	8.92	8.52	8.52
14.61	11.23	10.14	7.90	8.50	7.54	12.34	14.94
9.57	5.32	5.50	5.44	6.88	3.76	4.13	9.81
14.05	9.67	9.28	5.59	7.45	7.43	4.91	10.52
2.2	4.0	3.9	3.6	3.6	3.8	5.4	4.2
(116.6)	(30.3)	3.3	(15.8)	(10.0)	5.4	(1.2)	6.3
n/a	n/a	n/a	n/a	n/a	1.7	(2.3)	3.0
(4.5)	(1.5)	4.1	0.7	2.1	5.3	4.6	5.8
n/a	n/a	n/a	n/a	n/a	4.4	3.0	5.1
(1.0)	(0.5)	1.5	0.2	0.6	1.7	1.5	1.7
5.1	7.0	6.6	6.1	4.3	8.1	30.0	26.4
1,286	917	984	1,123	1,062	1,144	867	1,036
23.0	15.6	18.6	18.3	14.1	11.1	3.3	5.7
1.3	1.7	1.7	2.9	2.1	4.0	14.7	7.9
271	275	283	287	288	288	280	273
271	270	277	285	288	288	284	275
1,282	1,476	1,543	1,883	2,228	2,341	2,380	2,786
1,472	2,548	2,915	3,147	3,707	3,707	3,708	3,693
3,084	3,082	3,049	2,819	2,827	2,906	2,823	2,949
2,694	2,498	2,421	2,308	2,289	2,334	2,350	2,204
—	67	—	—	—	—	—	—
7,387	8,265	8,385	8,273	8,823	8,947	8,881	8,846
22,105	24,980	29,071	28,409	36,900	38,157	40,673	45,002

(2) During 2024 our adjusted EBITDA composition was amended to exclude the impact of Brazeau penalties and related provisions. Therefore, the Company has applied this composition to all previously reported periods.
(3) Total capital for 2014 has been revised to align with the 2015 calculation methodology.
(4) In 2022, the adjusted EBITDA composition was amended to include the impact of closed exchange positions that are effectively settled by offsetting positions with the same counterparty to reflect the performance of the assets and the Energy Marketing segment in the period in which the transactions occur. Therefore, the Company has applied this composition to 2022, 2021 and 2020 only. In 2019 and onwards adjusted EBITDA was adjusted to exclude the impact of unrealized mark-to-market gains or losses. 2018 and 2017 amounts were revised.
(5) 2016 and 2015 amounts were revised due to other revisions to EBITDA or FFO measures in the MD&A.
(6) 2014 to 2020 are gross installed capacity, which reflects the basis of underlying results. Prior year figures are as previously reported.
(7) Includes finance lease receivables.
(8) In 2021, Gas was adjusted to include the segments previously known as Austra ian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Prior year figures were revised.
(9) In 2021, Energy Transition was adjusted to include the segments previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal. Prior year figures were revised.

Ratio Formulas

Adjusted net debt to Adjusted EBITDA = long-term debt and lease liabilities including current portion + exchangeable securities + fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares and exchangeable preferred shares - cash and cash equivalents - principal portion of TransAlta OCP restricted cash / Adjusted EBITDA - PPA termination payments

Return on equity attributable to common shareholders = net earnings (loss) attributable to common shareholders excluding gain on discontinued operations or earnings on a comparable basis / equity attributable to common shareholders excluding AOCI

Return on capital employed = earnings (loss) before income taxes + net interest expense - net earnings (loss) attributable to non-controlling interests / total capital - AOCI

Earnings coverage = earnings (loss) before income taxes + net interest expense / 50 per cent dividends paid on preferred shares + interest on debt - interest income

Dividend payout ratio based on FFO = common share dividends paid / FFO - 50 per cent dividends paid on preferred shares

Dividend coverage = FFO - cash dividends paid on preferred shares + change in non-cash operating working capital balances / cash dividends paid on common shares

Dividend yield = dividends paid per common share / current year's closing price

Plant Summary

As at Dec. 31, 2024	Facility	Nameplate capacity (MW)[1]	Consolidated interest	Gross installed capacity[1]	Ownership (%)	Net capacity ownership interest (MW)[1]	Region	Revenue source	Contract expiry date
Hydro	Barrier, AB	13	100 %	13	100 %	13	Western Canada	Merchant	—
24 facilities	Bearspaw, AB	17	100 %	17	100 %	17	Western Canada	Merchant	—
	Belly River, AB	3	100 %	3	100 %	3	Western Canada	Merchant	—
	Bighorn, AB	120	100 %	120	100 %	120	Western Canada	Merchant	—
	Brazeau, AB	355	100 %	355	100 %	355	Western Canada	Merchant	—
	Cascade, AB	36	100 %	36	100 %	36	Western Canada	Merchant	—
	Ghost, AB	54	100 %	54	100 %	54	Western Canada	Merchant	—
	Horseshoe, AB	14	100 %	14	100 %	14	Western Canada	Merchant	—
	Interlakes, AB	5	100 %	5	100 %	5	Western Canada	Merchant	—
	Kananaskis, AB	19	100 %	19	100 %	19	Western Canada	Merchant	—
	Pocaterra, AB	15	100 %	15	100 %	15	Western Canada	Merchant	—
	Rundle, AB	50	100 %	50	100 %	50	Western Canada	Merchant	—
	Spray, AB	112	100 %	112	100 %	112	Western Canada	Merchant	—
	St. Mary, AB	2	100 %	2	100 %	2	Western Canada	Merchant	—
	Taylor, AB	13	100 %	13	100 %	13	Western Canada	Merchant	—
	Three Sisters, AB	3	100 %	3	100 %	3	Western Canada	Merchant	—
	Waterton, AB	3	100 %	3	100 %	3	Western Canada	Merchant	—
	Akolkolex, BC	10	100 %	10	100 %	10	Western Canada	LTC[2]	2046
	Bone Creek, BC	19	100 %	19	100 %	19	Western Canada	LTC	2031
	Pingston, BC	45	50 %	23	100 %	23	Western Canada	LTC	2043
	Upper Mamquam, BC	25	100 %	25	100 %	25	Western Canada	LTC	2045
	Misema, ON	3	100 %	3	100 %	3	Eastern Canada	LTC	2027
	Moose Rapids, ON	1	100 %	1	100 %	1	Eastern Canada	LTC	2030
	Ragged Chute, ON	7	100 %	7	100 %	7	Eastern Canada	LTC	2029
Total Hydro		944		922		922			
Wind &	Ardenville, AB	69	100 %	69	100 %	69	Western Canada	Merchant	—
Battery Storage	Blue Trail and Macleod Flats, AB	69	100 %	69	100 %	69	Western Canada	Merchant	—
32 facilities	Castle River, AB[3]	44	100 %	44	100 %	44	Western Canada	Merchant	—
	Cowley North, AB	20	100 %	20	100 %	20	Western Canada	Merchant	—
	Garden Plain, AB	130	100 %	130	100 %	130	Western Canada	LTC	2034-2041
	McBride Lake, AB	75	50 %	38	100 %	38	Western Canada	Merchant	
	Oldman, AB	4	100 %	4	100 %	4	Western Canada	Merchant	—
	Sinnott, AB	5	100 %	5	100 %	5	Western Canada	Merchant	—
	Soderglen, AB	71	50 %	36	100 %	36	Western Canada	Merchant	—
	Summerview 1, AB	68	100 %	68	100 %	68	Western Canada	Merchant	—
	Summerview 2, AB	66	100 %	66	100 %	66	Western Canada	Merchant	—
	WindCharger battery storage, AB	10	100 %	10	100 %	10	Western Canada	Merchant	—
	Windrise, AB	206	100 %	206	100 %	206	Western Canada	LTC	2041
	Kent Breeze, ON	20	100 %	20	100 %	20	Eastern Canada	LTC	2031
	Melancthon, ON[4]	200	100 %	200	100 %	200	Eastern Canada	LTC	2028-2031

As at Dec. 31, 2024	Facility	Nameplate capacity (MW)[1]	Consolidated interest	Gross installed capacity[1]	Ownership (%)	Net capacity ownership interest (MW)[1]	Region	Revenue source	Contract expiry date
	Wolfe Island, ON	198	100 %	198	100 %	198	Eastern Canada	LTC	2029
	Kent Hills, NB[5]	167	100 %	167	83 %	139	Eastern Canada	LTC	2045
	Le Nordais, QC	98	100 %	98	100 %	98	Eastern Canada	LTC	2033
	New Richmond, QC	68	100 %	68	100 %	68	Eastern Canada	LTC	2033
	Antrim, NH	29	100 %	29	100 %	29	United States	LTC	2039
	Big Level, PA	90	100 %	90	100 %	90	United States	LTC	2034
	Horizon Hill, OK	202	100 %	202	100 %	202	United States	LTC[13]	—
	Lakeswind, MN	50	100 %	50	100 %	50	United States	LTC	2034
	White Rock East, OK	202	100 %	202	100 %	202	United States	LTC[13]	—
	White Rock West, OK	100	100 %	100	100 %	100	United States	LTC[13]	—
	Wyoming Wind, WY	140	100 %	140	100 %	140	United States	LTC	2028
	Skookumchuck, WA	137	49 %	67	100 %	67	United States	LTC	2040
	Northern Goldfields Battery, WA[8]	10	100 %	10	100 %	10	Australia	LTC	2038
Total Wind		2548		2,406		2,378			
Solar	Mass Solar, MA[6]	21	100 %	21	100 %	21	United States	LTC	2032-2045
4 facilities	North Carolina Solar, NC[7]	122	100 %	122	100 %	122	United States	LTC	2033
	Northern Goldfields, WA[8]	38	100 %	38	100 %	38	Australia	LTC	2038
Total Solar		181		181		181			

Plant Summary

As at Dec. 31, 2024	Facility	Nameplate capacity (MW)[1]	Consolidated interest	Gross installed capacity[1]	Ownership (%)	Net capacity ownership interest (MW)[1]	Region	Revenue source	Contract expiry date
Gas	McMahon, BC	120	50 %	60	100 %	60	Western Canada	LTC	2029
26 facilities	Battle River 4, AB	155	100 %	155	100 %	155	Western Canada	Merchant	—
	Battle River 5, AB	395	100 %	395	100 %	395	Western Canada	Merchant	—
	Fort Saskatchewan, AB	118	60 %	71	50 %	35	Western Canada	LTC/Merchant	2029
	Joffre, AB	474	40 %	190	100 %	190	Western Canada	LTC/Merchant	2041
	Keephills 2, AB	395	100 %	395	100 %	395	Western Canada	Merchant	—
	Keephills 3, AB	466	100 %	466	100 %	466	Western Canada	Merchant	—
	Muskeg River, AB	202	100 %	202	100 %	202	Western Canada	LTC	2042
	Poplar Creek, AB[9]	230	100 %	230	100 %	230	Western Canada	LTC	2030
	Primrose, AB	100	50 %	50	100 %	50	Western Canada	LTC	2028
	Scotford, AB	195	100 %	195	100 %	195	Western Canada	LTC/Merchant	2043
	Sheerness, AB[4]	800	100 %	800	75 %	600	Western Canada	Merchant	—
	Sundance 6, AB	401	100 %	401	100 %	401	Western Canada	Merchant	—
	Valleyview 1, AB	50	100 %	50	100 %	50	Western Canada	Merchant	—
	Valleyview 2, AB	50	100 %	50	100 %	50	Western Canada	Merchant	—
	Ottawa, ON	74	100 %	74	50 %	37	Eastern Canada	LTC/ Merchant	2033
	Sarnia, ON	499	100 %	499	100 %	499	Eastern Canada	LTC	2031
	Windsor, ON	72	100 %	72	50 %	36	Eastern Canada	LTC/ Merchant	2031
	Ada, MI	29	100 %	29	100 %	29	United States	LTC	2026
	Fortescue River Gas Pipeline, WA	N/A	100 %	N/A	100 %	N/A	Australia	LTC	2035
	Parkeston, WA[10]	110	50 %	55	100 %	55	Australia	LTC/Merchant	2026
	Southern Cross, WA[11]	245	100 %	245	100 %	245	Australia	LTC	2038
	South Hedland, WA[12]	150	100 %	150	100 %	150	Australia	LTC	2042
Total Gas		5330		4834		4525			
Energy Transition	Centralia, WA	670	100 %	670	100 %	670	United States	LTC/ Merchant	2025[14]
2 facilities	Skookumchuck, WA	1	100 %	1	100 %	1	United States	LTC	2025
Total Energy Transition		671		671		671			
Total		9,674		9,014		8,677			

(1) MW are rounded to the nearest whole number; columns may not add due to rounding. The gross installed capacity reflects the basis of consolidation of underlying assets owned, net capacity ownership interest deducts capacity attributable to non-controlling interest in these assets and is calculated after consolidation of underlying assets.
(2) Long-term contract.
(3) Includes seven individual turbines at other locations.
(4) Comprised of two facilities.
(5) Comprised of three facilities.
(6) Comprised of four ground-mounted sites and four roof-top sites.
(7) Comprised of 20 sites.
(8) Comprises multiple facilities.
(9) The Poplar Creek plant is operated by Suncor and ownership of the facility will transfer to Suncor in 2030.
(10) The Parkeston facility is contracted to October 2023 with early termination options that begin in 2021.
(11) Comprised of four facilities. Does not include Northern Goldfields facilities that are in the Wind and Solar segment.
(12) The South Hedland facility is contracted with Fortescue Metals Group Ltd. ("FMG") and Horizon Power.
(13) The PPA term is confidential for the Horizon Hill and White Rock wind facilities.
(14) Contract is in place until 2025; however, Centralia Unit 1 was retired from service effective Dec. 31, 2020, and capacity decreased to 670 MW on Jan. 1, 2021.

Sustainability Performance Indicators

Performance below excludes the acquisition of Heartland Generation on Dec. 4, 2024. Refer to "Discussion and Notes on Numbers" for footnote explanations. √ 2024 data has been assured to a limited assurance level by Ernst & Young LLP. √√ indicates data for 2024, 2023 and 2022 has been assured to a limited assurance level by Ernst & Young LLP.

Environment, Health and Safety (EHS) Management Systems[2]	**2024**	**2023[1]**	**2022[1]**
EHS management system audits	**5**	5	4
Health and Safety compliance audits	**11**	3	9
Total EHS audits	**16**	8	13

Environmental Performance[3]	**2024**	**2023[1]**	**2022[1]**
Resource or energy use[4]			
Coal combustion (tonnes)	**1,772,000**	2,492,000	2,181,000
Diesel combustion (L)	**6,479,000**	6,920,000	6,685,000
Gasoline combustion (L)	**18,000**	3,000	3,000
Natural gas combustion (GJ)	**121,916,000**	123,067,000	130,023,000
Oil combustion (L)	**20,000**	26,000	15,000
Propane combustion (L)	**1,000**	2,000	3,000
Biodiesel consumption: vehicle (L)	**8,000**	10,000	14,000
Diesel consumption: vehicle (L)	**2,262,000**	2,315,000	3,261,000
Ethanol consumption: vehicle (L)	**11,000**	7,000	9,000
Gasoline consumption: vehicle (L)	**696,000**	608,000	605,000
Propane consumption: vehicle (L)	**8,000**	8,000	7,000
Electricity: building operations (MWh)	**162,000**	126,000	152,000
Kerosene: building operations (L)	**0**	0	3,000
Natural gas: building operations (GJ)	**148,000**	94,000	42,000
Propane: building operations (L)	**93,000**	110,000	169,000
Total resource or energy use (GJ)	**174,953,000**	197,357,000	186,393,000
Greenhouse gas (GHG) emissions			
Scope 1 and 2 GHG emissions[5]			
Carbon dioxide (tonnes CO_2e)	**9,463,000**	10,862,000	10,185,000
Methane (tonnes CO_2e)	**49,000**	26,000	24,000
Nitrous oxide (tonnes CO_2e)	**52,000**	36,000	40,000
Sulphur hexafluoride (tonnes CO_2e)	**230**	80	150
Total scope 1 and 2 GHG emissions (tonnes CO_2e)[6] √	**9,564,000**	10,924,000	10,249,000
GHG emission intensity (tonnes CO_2e/MWh)[7] √	**0.35**	0.41	0.40
Scope 1 emissions (tonnes CO_2e)	**9,497,000**	10,871,000	10,179,000
Scope 1 emissions (percentage of total GHG emissions)	**99**	100	99
Scope 1 emissions reported to national regulatory bodies (percentage)	**100**	100	100
Scope 2 emissions (tonnes CO_2e)[5]	**67,000**	53,000	70,000
Scope 2 emissions (percentage of total GHG emissions)	**1**	0	1
Total GHG emissions avoided (tonnes CO_2e)[8]	**2,818,000**	2,280,000	2,744,000
Scope 3 GHG emissions[9]			
Upstream scope 3 emissions			
Category 1: Purchased goods and services[10] √√	**30,000**	32,000	28,000
Category 2: Capital goods[11] √√	**24,000**	86,000	140,000

Environmental Performance *(continued)*	**2024**	**2023[1]**	**2022[1]**
Category 3: Fuel and energy related activities[12] √√	**950,000**	954,000	963,000
Downstream scope 3 emissions			
Category 11: Use of sold products[13] √√	**583,000**	716,000	556,000
Category 15: Investments[14] √√	**1,834,000**	1,651,000	1,846,000
Other relevant categories[15]	**242,000**	308,000	283,000
Total scope 3 GHG emissions (tonnes CO_2e)	**3,664,000**	3,747,000	3,816,000
Air emissions[16]			
Total sulphur dioxide emissions (tonnes) √	**870**	1,100	1,200
Sulphur dioxide emission intensity (kg/MWh) √	**0.03**	0.04	0.05
Total nitrogen oxide emissions (tonnes) √	**8,700**	11,000	11,000
Nitrogen oxide emission intensity (kg/MWh) √	**0.32**	0.40	0.43
Total particulate matter emissions (tonnes) √	**320**	460	360
Particulate matter emission intensity (kg/MWh) √	**0.01**	0.02	0.02
Total mercury emissions (kilograms)[16] √	**16**	21	21
Mercury emission intensity (mg/MWh)[16] √	**0.61**	0.80	0.83
Water management [17]			
Water withdrawal – other sources (million m^3)	**1**	1	1
Water withdrawal – surface water (million m^3)	**236**	272	232
Water withdrawn – all sources (million m^3) √	**237**	273	233
Water discharge – to other sources (million m^3)	**2**	1	0
Water discharge – surface water (million m^3)	**209**	238	207
Water discharge – all sources (million m^3) √	**212**	239	207
Water consumption (million m^3) √	**25**	34	26
Water consumption intensity (m^3/MWh)[18] √	**0.92**	1.25	1.03
Waste management[19]			
Diverted from disposal - Non-hazardous[20]			
Solid recycled (tonnes)	**2,000**	2,600	1,600
Liquid recycled (tonne eq.)	**210**	120	1,800
Reuse (tonnes)[20]	**372,000**	457,000	453,000
Storage (tonnes)[21]	**6**	1,400	26,000
Compost (tonnes)	**0**	1	0
Total non-hazardous waste diverted from disposal (tonnes)	**374,000**	461,000	485,000
Diverted from disposal - Hazardous			
Solid recycled (tonnes)	**2,600**	10	0
Liquid recycled (tonne eq.)	**6,700**	17,000	18,000
Total hazardous waste diverted from disposal (tonnes)	**9,300**	17,000	18,000
Total waste diverted from disposal (tonnes) √	**383,000**	478,000	503,000
Directed to disposal - Non-hazardous[22]			
Solid landfill (tonnes)	**780**	1,300	1,800
Liquid landfill (tonne eq.)	**34**	39	67
Ash disposal – mine (tonnes)[23]	**0**	0	2,900
Ash disposal – lagoon (tonnes)[24]	**0**	0	0
Total non-hazardous waste directed to disposal (tonnes)	**820**	1,300	4,800
Directed to disposal - Hazardous			
Solid landfill (tonnes)	**29**	0	81
Liquid landfill (tonne eq.)	**29**	10	46
Total hazardous waste directed to disposal (tonnes)	**58**	10	130
Total waste directed to disposal (tonnes) √	**880**	1,300	4,900

Environmental Performance *(continued)*	2024	2023[1]	2022[1]
Land use and reclamation[25]			
Land used in mining activities – disturbed (cumulative hectares)[25] √	**12,500**	12,500	12,500
Land used in mining activities – reclaimed (cumulative hectares)[25] √	**5,000**	5,000	4,800
Reclamation of land used in mining activities (percentage of land disturbed)[25] √	**40**	40	39
Land used in mining activities: disturbed minus reclaimed (hectares)[25] √	**7,500**	7,500	7,700
Land used by facilities, offices and equipment (hectares)[25] √	**4,000**	4,000	4,000
Total land use (cumulative hectares)[25] √	**11,500**	11,500	11,600
Environmental incidents[26]			
Significant environmental incidents	**0**	0	0
Regulatory non-compliance environmental incidents	**0**	0	1
Total environmental incidents √	**0**	0	1
Environmental enforcement actions[27]	**0**	0	2
Environmental fines ($ thousands)	**0**	0	35
Environmental spills[28]			
Volume of significant environmental spills (m^3)	**0**	0	246
Biodiversity-related incidents[29]			
Critically Endangered	**0**	0	0
Endangered	**0**	0	0
Vulnerable	**0**	0	0
Near threatened	**0**	0	0
Total biodiversity-related incidents	**0**	0	0

Social Performance	2024	2023	2022
Workplace practices			
Employees	**1,205**	1,257	1,222
Number of full-time employees	**1,165**	1,173	1,150
Number of part-time employees	**9**	11	14
Number of contingent employees	**31**	73	58
Employees represented by independent trade union organizations (percentage)[30]	**29**	30	31
Voluntary employee turnover rate (percentage)[31]	**18**	5	9
Health and safety			
Health and safety enforcement actions[32]	**0**	0	0
Health and safety fines ($ thousands)	**0**	0	0
Employee and contractor fatalities √	**0**	0	0
Lost-time injury (LTI) incidents (absence from work)[33] √	**0**	1	0
Medical aid (MA) incidents (no absence from work)[34] √	**6**	4	6
Restricted work injury (RWI) incidents (no absence from work)[35] √	**2**	0	0
Total recordable injuries to employees and contractors √	**8**	5	6
Exposure hours[36]	**2,844,000**	3,362,000	3,058,000
Total Recordable Injury Frequency (TRIF) (employees and contractors)[37] √	**0.56**	0.30	0.39
Community relations			
Community investments ($ millions)[38]	**2.9**	3.2	2.3

Governance Performance	2024	2023	2022
Diversity			
Women in workforce (percentage of all employees)	**28**	27	26
Women in senior management (percentage)	**32**	26	30
Women on Board of Directors (percentage)	**38**	46	36

Alignment of Sustainability Performance Indicators with Best Practice Sustainability Reporting Frameworks

The following outlines our sustainability or ESG performance indicator alignment with key criteria of GRI and SASB. Internally developed criteria are described in the footnotes to the Sustainability Performance Indicators.

Environment, Health and Safety (EHS) Management Systems	Criteria
EHS management system audits	Internally developed criteria[2]
Health and Safety compliance audits	Internally developed criteria[2]
Total EHS audits	

Environmental Performance	Criteria
Resource or energy use	GRI 302-1
Coal combustion (tonnes)	GRI 302-1
Natural gas combustion (GJ)	GRI 302-1
Diesel combustion (L)	GRI 302-1
Gasoline consumption: vehicle (L)	GRI 302-1
Diesel consumption: vehicle (L)	GRI 302-1
Propane consumption: vehicle (L)	GRI 302-1
Electricity: building operations (MWh)	GRI 302-1
Natural gas: building operations (GJ)	GRI 302-1
Propane: building operations (L)	GRI 302-1
Kerosene: building operations (L)	GRI 302-1
Total resource or energy use (GJ)	GRI 302-1
Greenhouse gas (GHG) emissions	
Carbon dioxide (tonnes CO_2e)	SASB IF-EU-110a.1
Methane (tonnes CO_2e)	SASB IF-EU-110a.1
Nitrous oxide (tonnes CO_2e)	SASB IF-EU-110a.1
Sulphur hexafluoride (tonnes CO_2e)	SASB IF-EU-110a.1
Total scope 1 and 2 GHG emissions (tonnes CO_2e)	Internally developed criteria[5][6]
GHG emission intensity (tonnes CO_2e/MWh)	GRI 305-4
Scope 1 emissions (tonnes CO_2e)	SASB IF-EU-110a.1
Scope 1 emissions (percentage of total GHG emissions)	SASB IF-EU-110a.1
Scope 1 emissions reported to national regulatory bodies (percentage)	SASB IF-EU-110a.1
Scope 2 emissions (tonnes CO_2e)	GRI 305-2
Scope 2 emissions (percentage of total GHG emissions)	GRI 305-2
Total GHG emissions avoided (tonnes CO_2e)	Internally developed criteria[8]
Scope 3 GHG emissions	
Upstream scope 3 emissions	
Category 1: Purchased goods and services	GHG Protocol
Category 2: Capital goods	GHG Protocol
Category 3: Fuel and energy related activities	GHG Protocol
Downstream scope 3 emissions	
Category 11: Use of sold product	GHG Protocol
Category 15: Investments	GHG Protocol
Other relevant categories	GHG Protocol
Total scope 3 GHG emissions (tonnes CO_2e)	GHG Protocol

Environmental Performance *(continued)*	**Criteria**
Air emissions	
Total sulphur dioxide emissions (tonnes)	SASB IF-EU-120a.1
Sulphur dioxide emission intensity (kg/MWh)	Internally developed criteria[16]
Total nitrogen oxide emissions (tonnes)	SASB IF-EU-120a.1
Nitrogen oxide emission intensity (kg/MWh)	Internally developed criteria[16]
Total particulate matter emissions (tonnes)	SASB IF-EU-120a.1
Particulate matter emission intensity (kg/MWh)	Internally developed criteria[16]
Total mercury emissions (kilograms)	SASB IF-EU-120a.1
Mercury emission intensity (mg/MWh)	Internally developed criteria[16]
Water management	
Water withdrawal – water utility/municipality/customer (million m^3)	SASB IF-EU-140a.1
Water withdrawal – surface water (million m^3)	SASB IF-EU-140a.1
Water withdrawn – all sources (million m^3)	SASB IF-EU-140a.1
Water discharge – all sources (million m^3)	Internally developed criteria[17]
Water consumption (million m^3)	SASB IF-EU-140a.1
Water consumption intensity (m^3/MWh)	Internally developed criteria[18]
Waste management	
Diverted from disposal - Non-hazardous	
Recycled (tonnes)	GRI 306-4
Recycled (L)	GRI 306-4
Reuse (tonnes)	GRI 306-4
Storage (tonnes)	GRI 306-4
Total non-hazardous waste diverted from disposal (tonnes)	GRI 306-4
Diverted from disposal - Hazardous	
Recycled (tonnes)	GRI 306-4
Recycled (L)	GRI 306-4
Total hazardous waste diverted from disposal (tonnes)	GRI 306-4
Total waste diverted from disposal (tonnes)	GRI 306-4
Directed to disposal - Non-hazardous	
Landfill (tonnes)	GRI 306-5
Landfill (L)	GRI 306-5
Ash disposal – mine (tonnes)	GRI 306-5
Ash disposal – lagoon (tonnes)	GRI 306-5
Compostable (tonnes)	GRI 306-5
Total non-hazardous waste directed to disposal (tonnes)	GRI 306-5
Directed to disposal - Hazardous	
Landfill (tonnes)	GRI 306-5
Landfill (L)	GRI 306-5
Total hazardous waste directed to disposal (tonnes)	GRI 306-5
Total waste directed to disposal (tonnes)	GRI 306-5
Land use and reclamation	
Land used in mining activities – disturbed (cumulative hectares)	Internally developed criteria[25]
Land used in mining activities – reclaimed (cumulative hectares)	Internally developed criteria[25]
Reclamation of land used in mining activities (percentage of land disturbed)	Internally developed criteria[25]
Land used in mining activities: disturbed minus reclaimed (hectares)	Internally developed criteria[25]
Land used by plants, offices and equipment (hectares)	Internally developed criteria[25]
Total land use (cumulative hectares)	Internally developed criteria[25]

Environmental Performance *(continued)*	Criteria
Environmental incidents	
Significant environmental incidents	Internally developed criteria[26]
Regulatory non-compliance environmental incidents	GRI 2-27
Total environmental incidents	Internally developed criteria[26]
Environmental enforcement actions	GRI 2-27
Environmental fines ($ thousands)	GRI 2-27
Environmental spills	
Volume of significant spills (m^3)	GRI 306-3
Biodiversity-related incidents	
Critically Endangered	Internally developed criteria[29]
Endangered	Internally developed criteria[29]
Vulnerable	Internally developed criteria[29]
Near threatened	Internally developed criteria[29]
Total biodiversity-related incidents	Internally developed criteria[29]

Social Performance	Criteria
Workplace practices	
Employees	GRI 102-7
Number of full-time employees	Internally developed criteria
Number of part-time employees	Internally developed criteria
Number of contingent employees	Internally developed criteria
Employees represented by independent trade union organizations (percentage)	GRI 102-41
Voluntary employee turnover rate (percentage)	GRI 401-1
Health and safety	
Health and safety enforcement actions	Internally developed criteria[32]
Health and safety fines ($ thousands)	Internally developed criteria[32]
Employee and contractor fatalities	SASB IF-EU-320a.1
Lost-time injury (LTI) incidents (absence from work)	SASB IF-EU-320a.1
Medical aid (MA) incidents (no absence from work)	SASB IF-EU-320a.1
Restricted work injury (RWI) incidents (no absence from work)	SASB IF-EU-320a.1
Total injuries to employees and contractors	SASB IF-EU-320a.1
Exposure hours	SASB IF-EU-320a.1
Total Recordable Injury Frequency (TRIF) (employees and contractors)	SASB IF-EU-320a.1
Community relations	
Community investments ($ millions)	GRI 203-1

Governance Performance	Criteria
Diversity	
Women in workforce (percentage of all employees)	GRI 405-1
Women in senior management (percentage)	GRI 405-1
Women on Board of Directors (percentage)	GRI 405-1

Discussion and Notes on Numbers

TransAlta strives to improve the accuracy and scope of our sustainability performance data. We continually review our processes and controls relating to the measurement and calculation of key sustainability data annually. Several footnotes appear throughout the statistical summary and are intended to provide clarity on specific boundary conditions, changes in methodology and definitions. For questions or clarity on any key performance indicators, please contact us at **sustainability@transalta.com**.

1. Some of the values related to 2022 and 2023 have been restated to reflect better available data or correction of errors regardless of magnitude to be reported with complete accuracy. Refer to end notes associated with individual performance indicators which identify and explain nature of restatement from previously reported values.
2. EHS management system audits are conducted annually to assesses conformance to our environmental, health and safety management systems. Health and Safety compliance audits are conducted to verify compliance to internal health and safety standards and procedures and defined occupational health and safety regulatory requirements.
3. Environmental performance figures have been rounded based on the following methodology: i) All environmental data between 0-100 are rounded to the nearest whole number, 100-1,000 to the nearest 10, 1,000-10,000 to the nearest hundred, and above 10,000 to the nearest thousand; ii) Water data is rounded to the nearest million; iii) Land use data, which is smaller in magnitude compared with other environmental indicators, is rounded to the nearest 100 to represent a more accurate picture of management and progress. Some values may not sum to the indicated total due to rounding.
4. Energy use is calculated and reported from TransAlta-operated facilities, following the same approach we use for GHG emissions reporting, which is the application of an 'Operational Control' boundary as per guidance from the GHG Protocol: A Corporate Accounting and Reporting Standard. The energy use data for years 2022 and 2023 differ from previous years as the categories of fuel/energy have been expanded to better reflect our activity consumption.
5. Scope 1 and 2 GHG emissions are calculated and reported from TransAlta-operated facilities in line with carbon compliance regulations from the geographic jurisdiction where the facility is located. For GHG emissions that are not calculated using jurisdictional carbon compliance guidance, we follow guidance from the GHG Protocol: A Corporate Accounting and Reporting Standard (specifically 'Setting Organizational Boundaries: Operational Control' methodology). As per the operational control methodology, TransAlta reports 100 per cent of GHG emissions from facilities at which we are the operator. GHG emissions include emissions from stationary combustion, transportation use, building use and fugitive emissions. If we were to use a financial boundary, there would be no material impact. We report both scope 1 and 2 emissions. We compile our corporate GHG inventory using our business segment GHG calculations. All of our scope 1 emissions (100 per cent) are reported to national regulatory bodies in the country in which we operate. This includes: Australia (National Greenhouse and Energy Reporting), Canada (Greenhouse Gas Reporting Program, National Pollutant Release Inventory) and the U.S. (EPA). Our scope 1 and 2 emissions use global warming potentials and emissions factors that vary with respect to regional compliance guidance and include IPCC Fifth Assessment Report, Canada's GHG Inventory 1990-2022, U.S. Emission Factors for Greenhouse Gas Inventories 2024, U.S. EPA eGRID Summary Tables 2022 and Australia Greenhouse Account Factors 2024. Scope 2 for years 2022 and 2023 have been restated due to calculation error.
6. 'Total scope 1 and 2 GHG emissions' is the sum of the reported 'scope 1 emissions' which have been reported in accordance with SASB IF-EU-110a.1 and the reported 'scope 2 emissions' which have been reported in accordance with GRI 305-2. Total scope 1 and 2 GHG emissions is the sum of applicable gases which include carbon dioxide, methane, nitrous oxide and sulphur hexafluoride (SF_6).
7. GHG emission intensity is calculated by dividing total scope 1 and scope 2 emissions by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership.
8. Avoided emissions are defined as the emissions that are displaced from the power grid through renewables generation instead of standard consumption via the grid. This is calculated by multiplying the total renewable production with the grid carbon intensity of the jurisdiction it operates in.
9. Scope 3 emissions are all indirect emissions (not included in scope 1 or 2) that occur in the value chain of the reporting company, including both upstream and downstream emissions. TransAlta's scope 3 emissions are calculated using methodologies consistent with

the GHG Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard and with reference to the additional guidance provided in the GHG Protocol Technical Guidance for Calculating Scope 3 Emissions. Upstream scope 3 emissions are the indirect emissions related to TransAlta's suppliers. Downstream scope 3 emissions are the emissions related to TransAlta's customers. Of the 15 categories described in the GHG Protocol Scope 3 Guidance, four are not relevant to our business and, therefore, are not included in the calculation: Category 8: Upstream leased assets, Category 12: End-of-life treatment of sold products, Category 13: Downstream leased assets, and Category 14: Franchises. Our scope 3 emissions use global warming potentials sourced from IPCC Fourth Assessment Report for 2022 and IPCC Fifth Assessment Report for 2023 and 2024.

10. Category 1: Purchased goods and services includes emissions associated with purchased of goods and services described as operating expenses less labour, wages and other related costs. The accounting approach includes all upstream (cradle to gate) GHG emissions from the extraction, production, and transportation of goods and services purchased or acquired by the Company in the reporting year, where not otherwise included in Categories 2 to 8. The methodology utilizes the spend-based approach and emissions are calculated from the operating expense of purchases of goods and services and the emission factors from U.S. EPA Environmentally-Extended Input-Output (EEIO) models.

11. Category 2: Capital goods includes emissions associated with purchased of capital goods and services described as capital expenditures. The accounting approach includes all upstream (cradle to gate) GHG emissions from the production of capital goods or services purchased or acquired by the Company in the reporting year, where not otherwise included in Categories 1 and from 3 to 8. The methodology utilizes the spend-based approach and emissions are calculated from the capital expense of purchases of capital goods and the emission factors from U.S. EPA Environmentally-Extended Input-Output (EEIO) models.

12. Category 3: Fuel and energy related activities includes emissions associated with the extraction, production and midstream transportation of natural gas (pipeline). Excludes the emissions associated with electricity consumption as they have been accounted for in our scope 2 GHG emissions but accounting for the transmission and distribution losses. The activities applicable are a) upstream emissions of purchased fuels and c) transmission and distribution losses of purchased electricity. The methodology utilizes the average-data approach and emissions are calculated from the resource or energy use and the emission factors from Canada's GHG Inventory, U.S. Emission Factors for Greenhouse Gas Inventories and Australia Greenhouse Account Factors.

13. Category 11: Use of sold products includes emissions associated with natural gas combustion during electricity production where the sales and delivery of physical natural gas occur. TransAlta is considered an intermediary between the natural gas producer whom we purchased it from to the client, for sole purpose of combustion for electricity production. As such, we account for the direct use-phase emissions associated with the combustion of natural gas, categorized under fuels and feedstocks. The methodology utilizes the amount of fuel sold in Alberta and British Columbia in Canada multiplying it with representative emission factors from Canada's GHG Inventory 1990-2022.

14. Category 15: Investments includes emissions from our assets that are owned (as a joint venture or other ownership structure) but not operated by TransAlta. The joint venture assets utilize an equity-based investment on the asset's scope 1 and 2 GHG emissions.

15. In 2024, relevant scope 3 categories that did not receive limited assurance by a third-party provider include Category 4: Upstream transportation and distribution, Category 5: Waste generated in operations, Category 6: Business travel, Category 7: Employee commuting, Category 9: Downstream transportation and distribution, and Category 10: Processing of sold products.

16. Air emissions which are applicable to TransAlta's operations are NOx, SO_2, particulate matter (PM2.5 and PM10) and mercury. The applicable air emissions are calculated and reported from TransAlta-operated facilities, following the same approach we use for GHG emissions reporting, which is the application of an 'Operational Control' boundary as per guidance from the GHG Protocol: A Corporate Accounting and Reporting Standard. Air emissions are expressed in tonnes, except for mercury emissions, which are represented in kilograms. Particulate matter emissions include both PM2.5 and PM10. Air emission intensities are calculated by dividing total emissions by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership. In 2024, PM emissions factor utilized for certain facilities was updated to a more applicable source, contributing to a 31 per cent decrease from 2023, as the prior year amounts have not been restated to reflect this updated emission factor. We have restated our 2023 mercury emissions and mercury emissions intensity following the discovery of an error related to conversion. The restatement increases the original

2023 mercury by 3 kg and the mercury intensity by 0.13 mg/MWh.

17. Water use is calculated and reported from TransAlta-operated facilities, following the same approach we use for GHG emissions reporting, which is the application of an 'Operational Control' boundary as per guidance from the GHG Protocol: A Corporate Accounting and Reporting Standard. Total water consumed is measured by total water withdrawal minus water discharge, where water withdrawal are sourced from surface water, groundwater, third-party, or non-freshwater, and water discharge refers to the volume of freshwater leaving the organization's boundary and released to surface water, groundwater, or to third parties. Water is used primarily for cooling by our thermal power plants. Evaporative losses from cooling ponds and cooling towers account for the majority of consumptive loss. The water lost to evaporation is not returned directly to the water body, but the water remains in the hydrologic cycle.

18. Water intensity is calculated by dividing total operational water consumption (m^3) by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership.

19. Waste is categorized as either non-hazardous or hazardous waste. Non-hazardous waste includes, but is not limited to, water treatment chemicals, coal refuse (including ash byproducts), metals, paper, cardboard and building materials. Hazardous wastes can be harmful to people, plants, animals or the environment, either in the short or the long term, and TransAlta is required in all of its operating jurisdictions to follow proper procedures for landfill/recycling of these materials. We measure and report the total weight of all types of waste generated and use several methods for calculation, including direct measurement of quantity onsite, by transporters at the point of shipping or loading (consistent with shipping papers), by waste disposal contractor at the point of waste disposal or by transporters, at the point of shipping or loading, and engineering estimates or process knowledge. The unit measurement for all types of waste is reported as metric ton. Unless specified that it is on-site, all waste generated are disposed off-site from our facilities.

20. Waste diverted from disposal refers to the recycling or reuse of waste that would otherwise end up in the landfill. We have restated our 2022 waste – reuse following the discovery of an error related to data aggregation error. The restatement increases the original 2022 data by 302,000 tonnes.

21. Storage waste is ash product from coal production, which is stored on-site for treatment prior to sales for cement production.

22. Waste directed to disposal refers to waste that ends up in the landfill.

23. Ash disposal – mine is fly ash and bottom ash from coal production, which is treated and then returned to its original source, the mine, for landfill/disposal. In 2024, we reported zero as we have ceased coal operations in Canada; therefore, we have no ash waste to dispose of.

24. Ash disposal – lagoon is fly ash and bottom ash from Keephills coal production, which is treated and then sent to ash lagoons for disposal. In 2024, we reported zero as we have ceased coal operations in Canada; therefore, we have no ash waste to dispose of.

25. Land used in mining activities – disturbed refers to the total active footprint of our mining operations, which includes the cumulative hectares for land cleared of vegetation, soil disturbed, ready for reclamation, soils placed, and permanently reclaimed: (i) Disturbed means soil has been disturbed; (ii) Cleared means vegetation has been removed and soils are intact; (iii) Reclamation means the restoration of disturbed lands to similar pre-development condition, other economically productive use, or natural or semi-natural habitat. Land reclamation refers to the ratio between the land that has been permanently or temporarily reclaimed and the total active footprint of our mining operations. Reclamation is presented as a cumulative number; therefore, the total number of hectares reported from year to year may increase depending on whether reclamation has occurred or whether re-disturbance of previously reclaimed areas was required. Total land use refers to the total active footprint of all our operations or the sum of the land used in mining activities plus land used by plants, offices and equipment. We have restated our 2022 and 2023 land use for mining activities (disturbed and reclaimed) following an update to historical estimation and this is done in line with internal policy to update for most recent information even if it is not considered material. We have restated our 2022 and 2023 land use for facilities, offices and equipment following the discovery of an error related to conversion. The restatement decreases our original 2022 and 2023 data by 1000 hectares.

26. Environmental incidents are separated into two categories: significant environmental incidents (internally defined) and regulatory non-compliance environmental incidents (aligned to GRI 2-27). We define significant environmental incidents as an incident that is internally classified as moderate, significant, major or extreme, that resulted in an impact to the ecosystem that is reversible or irreversible. Factors that impact this classification include mortalities of greater than 0.01 per cent of a given species when compared to the overall population, as

well as other relevant qualitative factors. We define regulatory non-compliance environmental incidents as violations or non-compliance to regulations or exceedance of limits in company operating approvals that result in enforcement action including fines or stop work orders that suspend overall facility or site operations, but did not have an impact on the environment. For example, a technical issue with a computer system for gathering real-time data could cause us to be out of compliance with local regulation or our EMS, but there is no direct consequence for the physical environment.

27. Environmental enforcement actions are a violation or non-compliance to regulations or exceedance of limits in company operating approvals that result in an impact on the environment and enforcement action including stop work orders, fines or suspension of operating approvals.

28. Environmental spills generally happen in low environmental impact areas and are almost always contained and fully recovered. It is extremely rare that we experience large spills, which could adversely impact the environment and the Company.

29. Biodiversity incidents are the number of total biodiversity-related incidents that are classified as a significant environmental incident and that affect habitats and species included on the Red List of the International Union for Conservation of Nature and are classified as near-threatened, vulnerable, endangered and critically endangered.

30. In 2024, TransAlta employed approximately 351 unionized workers working primarily in our operational business units.

31. Voluntary turnover is aligned with our Human Resources voluntary turnover reporting methodology. As per this methodology, voluntary turnover is any full-time, part-time or contingent employee initiated exit, excluding retirement. Summer students and temporary workers are not considered within voluntary turnover.

32. Health and safety enforcement actions are a violation of or non-compliance with regulations or exceedance of limits in company operating approvals that result in enforcement action including stop work orders, fines or suspension of operating approvals.

33. Lost-time injuries (LTI) are injuries that resulted in the worker being away from work beyond the day of the injury.

34. Medical aids (MA) are injuries that resulted in medical treatment beyond first aid.

35. Restricted work injuries (RWI) are injuries that resulted in the worker being unable to perform all normally scheduled and assigned work activities.

36. Exposure hours are total hours worked by all TransAlta employees and contractors, and include full-time, part-time, direct, contract, executive, labour, salary, hourly and seasonal employees in all locations, but exclude prime contractors. Prime contractor is the person responsible for legislative compliance for safety in multiple employer work site situations under applicable law in the jurisdictions where we operate. Exposure hours from prime contractors are excluded as we do not direct their work. Exposure hours have been rounded to the nearest thousand.

37. Total Recordable Injury Frequency (TRIF) measures restricted work, medical aid and lost-time injuries per 200,000 hours worked. It does not include near miss as per the SASB IF EU 320a.1 criteria.

38. Cumulative of donations and sponsorship totals in the respective calendar year. This investment figure does not include donations from our employees.

Independent Practitioner's Assurance Report

To Management of TransAlta Corporation

Scope

We have been engaged by TransAlta Corporation ("TransAlta") to perform a 'limited assurance engagement,' as defined by International Standards on Assurance Engagements, hereafter referred to as the engagement, to report on select performance indicators detailed in the accompanying schedule (the "Subject Matter") and contained in TransAlta's 2024 Annual Integrated Report (the "Report").

Other than as described in the preceding paragraph, which sets out the scope of our engagement, this engagement did not include performing assurance procedures on the remaining information included in the Report, and accordingly, we do not express a conclusion on this information.

Criteria applied by TransAlta

In preparing the Subject Matter, TransAlta applied relevant guidance contained within the Sustainability Accounting Standards Board ("SASB") Standards, Global Reporting Initiative ("GRI") Sustainability Reporting Standards, the Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard ("GHG Protocol") and internally developed criteria, as detailed in the accompanying Schedule, collectively referred to herein as (the "Criteria"). The internally developed criteria were specifically designed for the preparation of the Report. As a result, the Subject Matter may not be suitable for another purpose.

TransAlta's responsibilities

TransAlta's management is responsible for selecting the Criteria, and for presenting the Subject Matter in accordance with that Criteria, in all material respects. This responsibility includes establishing and maintaining internal controls, maintaining adequate records and making estimates that are relevant to the preparation of the Subject Matter, such that it is free from material misstatement, whether due to fraud or error.

EY's responsibilities

Our responsibility is to express a conclusion on the presentation of the Subject Matter based on the evidence we have obtained.

We conducted our engagement in accordance with the *International Standard for Assurance Engagements ("ISAE") 3000, Assurance Engagements Other than Audits or Reviews of Historical Financial Information ("ISAE 3000") and ISAE 3410, Assurance Engagements on Greenhouse Gas Statements ("ISAE 3410")*. These standards require that we plan and perform our engagement to obtain limited assurance about whether, in all material respects, the Subject Matter is presented in accordance with the Criteria, and to issue a report. The nature, timing and extent of the procedures selected depend on our judgment, including an assessment of the risk of material misstatement, whether due to fraud or error.

We believe that the evidence obtained is sufficient and appropriate to provide a basis for our limited assurance conclusion.

Our independence and quality management

We have complied with the relevant rules of professional conduct / code of ethics applicable to the practice of public accounting and related to assurance engagements, issued by various professional accounting bodies, which are founded on fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behaviour.

Our firm applies Canadian Standard on *Quality Management 1, Quality Management for Firms that Perform Audits or Reviews of Financial Statements, or Other Assurance or Related Services Engagements*, which requires us to design, implement and operate a system of quality management including policies or procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

Description of procedures performed

Procedures performed in a limited assurance engagement vary in nature and timing from, and are less in extent than for, a reasonable assurance engagement. Consequently, the level of assurance obtained in a limited assurance engagement is substantially lower than the assurance that would have been obtained had a reasonable assurance engagement been performed. Our procedures were designed to obtain a limited level of assurance on which to base our conclusion and do not provide all the evidence that would be required to provide a reasonable level of assurance.

Although we considered the effectiveness of management's internal controls when determining the nature and extent of our procedures, our assurance engagement was not designed to provide assurance on internal controls. Our procedures did not include testing controls or performing procedures relating to checking aggregation or calculation of data within IT systems.

A limited assurance engagement consists of making enquiries, primarily of persons responsible for preparing the Subject Matter and related information, and applying analytical and other appropriate procedures.

Our procedures included:

- Conducting interviews with relevant personnel to obtain an understanding of the reporting processes;
- Inquiries of relevant personnel who are responsible for the Subject Matter including, where relevant, observing and inspecting systems and processes for data aggregation and reporting in accordance with the Criteria;
- Assessing the accuracy of data, through analytical procedures and limited reperformance of calculations, where applicable, and tested, on a limited sample basis, underlying source information to support completeness and accuracy of the Subject Matter; and
- Checking presentation and disclosure of the Subject Matter in the Report.

We also performed such other procedures as we considered necessary in the circumstances.

Inherent limitations

The Greenhouse Gas ("GHG") quantification process is subject to scientific uncertainty, which arises because of incomplete scientific knowledge about the measurement of GHGs. Additionally, GHG procedures are subject to estimation (or measurement) uncertainty resulting from the measurement and calculation processes used to quantify emissions within the bounds of existing scientific knowledge.

Non-financial information, such as the Subject Matter, is subject to more inherent limitations than financial information, given the more qualitative characteristics of the subject matter and the methods used for determining such information. The absence of a significant body of established practice on which to draw allows for the selection of different but acceptable evaluation techniques which can result in materially different evaluation and can impact comparability between entities and over time.

Conclusion

Based on our procedures and the evidence obtained, nothing has come to our attention that causes us to believe that the Subject Matter for the reporting periods outlined in the accompanying schedule and the Report, are not prepared, in all material respects, in accordance with the Criteria.

Ernst & Young LLP

Chartered Professional Accountants

Calgary, Canada
February 19, 2025

Schedule

Our limited assurance engagement was performed on the following Subject Matter:

Performance Indicator	Criteria	Reported Value for the year ended December 31, 2024[1]	Unit of Measure
Greenhouse Gas Emissions			
Scope 1 and 2 emissions	Internally developed criteria[2]	9,564,000	Tonnes CO_2e
Greenhouse gas emission intensity	GRI 305-4	0.35	Tonnes CO_2e /MWh
Air Emissions			
Total sulphur dioxide emissions	SASB IF-EU-120a.1	870	Tonnes
Sulphur dioxide emission intensity	Internally developed criteria[3]	0.03	kg/MWh
Total nitrogen oxide emissions	SASB IF-EU-120a.1	8,700	Tonnes
Nitrogen oxide emission intensity	Internally developed criteria[3]	0.32	kg/MWh
Total particulate matter emissions	SASB IF-EU-120a.1	320	Tonnes
Particulate matter emission intensity	Internally developed criteria[3]	0.01	kg/MWh
Total mercury emissions	SASB IF-EU-120a.1	16	kg
Mercury emission intensity	Internally developed criteria[3]	0.61	mg/MWh
Water Management			
Water withdrawn – all sources	SASB IF-EU-140a.1	237	Million m^3
Water discharge – all sources	Internally developed criteria[4]	212	Million m^3
Water consumption	SASB IF-EU-140a.1	25	Million m^3
Water consumption intensity	Internally developed criteria[5]	0.92	m^3/MWh
Waste Management			
Total waste diverted from disposal	GRI 306-4	383,000	Tonnes
Total waste directed to disposal	GRI 306-5	880	Tonnes
Land Use and Reclamation			
Land used in mining activities – disturbed	Internally developed criteria[6]	12,500	Cumulative hectares
Land used in mining activities – reclaimed	Internally developed criteria[6]	5,000	Cumulative hectares
Reclamation of land used in mining activities	Internally developed criteria[6]	40	% of land disturbed
Land used in mining activities: disturbed minus reclaimed	Internally developed criteria[6]	7,500	Hectares

Performance Indicator	Criteria	Reported Value for the year ended December 31, 2024[1]	Unit of Measure
Land used by facilities, offices and equipment	Internally developed criteria[6]	4,000	Hectares
Total land use	Internally developed criteria[6]	11,500	Cumulative hectares
Environmental Incidents			
Total environmental incidents	Internally developed criteria[7]	0	Number
Health and Safety			
Employee and contractor fatalities	SASB IF-EU-320a.1[8]	0	Number
Lost-time injury (LTI) incidents	SASB IF-EU-320a.1[8]	0	Number
Medical aid (MA) incidents	SASB IF-EU-320a.1[8]	6	Number
Restricted work injury (RWI) incidents	SASB IF-EU-320a.1[8]	2	Number
Total recordable injuries to employees and contractors	SASB IF-EU-320a.1[8]	8	Number
Total Recordable Injury Frequency (TRIF) (employees and contractors)	SASB IF-EU-320a.1[8]	0.56	Rate

Performance Indicator	Criteria	Reported Value for the year ended December 31, 2024[1]	Reported Value for the year ended December 31, 2023[1]	Reported Value for the year ended December 31, 2022[1]	Unit of Measure
Greenhouse Gas Emissions					
Scope 3 Category 1 emissions	GHG Protocol[9]	30,000	32,000	28,000	Tonnes CO_2e
Scope 3 Category 2 emissions	GHG Protocol[9]	24,000	86,000	140,000	Tonnes CO_2e
Scope 3 Category 3 emissions	GHG Protocol[9]	950,000	954,000	963,000	Tonnes CO_2e
Scope 3 Category 11 emissions	GHG Protocol[9]	583,000	716,000	556,000	Tonnes CO_2e
Scope 3 Category 15 emissions	GHG Protocol[9]	1,834,000	1,651,000	1,846,000	Tonnes CO_2e

(1) All figures have been rounded in accordance with footnote 3 in the Sustainability Performance Indicators section of the Report.
(2) As described in the footnote 6 in the Sustainability Performance Indicators section of the Report.
(3) As described in the footnote 16 in the Sustainability Performance Indicators section of the Report.
(4) As described in the footnote 17 in the Sustainability Performance Indicators section of the Report.
(5) As described in the footnote 18 in the Sustainability Performance Indicators section of the Report.
(6) As described in the footnote 25 in the Sustainabi ity Performance Indicators section of the Report.
(7) As described in the footnote 26 in the Sustainabi ity Performance Indicators section of the Report.
(8) Other criteria included in SASB Disclosure IF-EU-320a.1 (3), near miss frequency rate (NMFR), is excluded from the scope of our limited assurance engagement
(9) Reported Scope 3 emissions are calculated in accordance with the methodologies in the GHG Protocol Technical Guidance for Calculating Scope 3 Emissions

Shareholder Information

Special Services for Registered Shareholders

Service	Description
Direct deposit for dividend payments	Automatically have dividend payments deposited to your bank account
Account consolidations	Eliminate costly duplicate mailings by consolidating account registrations
Address changes and share transfers	Receive tax splits and dividends without the delays resulting from address and ownership changes

Stock Splits and Share Consolidations

Date	Events
May 8, 1980	Stock split
February 1, 1988	Stock split[1]
December 31, 1992	Reorganization — TransAlta Utilities shares exchanged for TransAlta Corporation shares[2] 1:1

The valuation date value of common shares owned on December 31, 1971, adjusted for stock splits, is $4.54 per share.

(1) The adjusted cost base for shares held on January 31, 1988, was reduced by $0.75 per share following the February 1, 1988, share split.

(2) TransAlta Utilities Corporation became a wholly owned subsidiary of TransAlta Corporation as a result of this reorganization.

Dividend Declaration for Common Shares

Dividends are paid quarterly as determined by the Board. Dividends on our common shares are at the discretion of the Board. In determining the payment and level of future dividends, the Board considers our financial performance, results of operations, cash flow and needs with respect to financing our ongoing operations and growth, balanced against returning capital to shareholders. The Board continues to focus on building sustainable earnings and cash flow growth.

Common Share Dividends Declared in 2024

Payment Date	Record Date	Ex-Dividend Date	Dividend
April 1, 2024	March 1, 2024	Feb. 28, 2024	$0.060
July 1, 2024	June 1, 2024	May 31, 2024	$0.060
Oct. 1, 2024	Sept. 1,2024	Aug. 31, 2024	$0.060
Jan. 1, 2025	Dec. 1, 2024	Nov. 30, 2024	$0.060

Submission of Concerns Regarding Accounting or Auditing Matters

TransAlta has adopted a procedure for employees, shareholders or others to report concerns or complaints regarding accounting or other matters on an anonymous, confidential basis to the Audit, Finance and Risk Committee of the Board of Directors. Such submissions may be directed to the Audit, Finance and Risk Committee c/o the Chief Officer, Legal, Regulatory and External Affairs, of the Company.

Dividend Declaration for Preferred Shares

Series A: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $0.71924 per share from and including March 31, 2021, to, but excluding, March 31, 2026.

Series B: Floating cumulative preferential cash dividends are paid quarterly when declared by the Board from and including March 31, 2021, to, but excluding, March 31, 2026.

Series C: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.46352 per share from and including June 30, 2022, to, but excluding, June 30, 2027.

Series D: Floating cumulative preferential cash dividends are paid quarterly when declared by the Board from and including June 30, 2022, to, but excluding, June 30, 2027.

Series E: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.72352 per share from and including September 30, 2022, to, but excluding, September 30, 2027.

Series G: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.47012 per share from and including September 30, 2024, to, but excluding, September 30, 2029.

Preferred Share Dividends Declared in 2024

Series A

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2024	March 1, 2024	Feb. 28, 2024	$0.17981
June 30, 2024	June 1, 2024	May 31, 2024	$0.17981
Sept. 30, 2024	Sept. 1, 2024	Aug. 31, 2024	$0.17981
Dec. 31, 2024	Dec. 1, 2024	Nov. 30, 2024	$0.17981
March 31, 2025	March 1, 2025	Feb. 28, 2025	$0.17981

Series B

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2024	March 1, 2024	Feb. 28, 2024	$0.43958
June 30, 2024	June 1, 2024	May 31, 2024	$0.43579
Sept. 30, 2024	Sept. 1, 2024	Aug. 31, 2024	$0.43371
Dec. 31, 2024	Dec. 1, 2024	Nov. 30, 2024	$0.39182
March 31, 2025	March 1, 2025	Feb. 28, 2025	$0.33972

Series C

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2024	March 1, 2024	Feb. 28, 2024	$0.36588
June 30, 2024	June 1, 2024	May 31, 2024	$0.36588
Sept. 30, 2024	Sept. 1, 2024	Aug. 31, 2024	$0.36588
Dec. 31, 2024	Dec. 1, 2024	Nov. 30, 2024	$0.36588
March 31, 2025	March 1, 2025	Feb. 28, 2025	$0.36588

Series D

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2024	March 1, 2024	Feb. 28, 2024	$0.50609
June 30, 2024	June 1, 2024	May 31, 2024	$0.50230
Sept. 30, 2024	Sept. 1, 2024	Aug. 31, 2024	$0.50097
Dec. 31, 2024	Dec. 1, 2024	Nov. 30, 2024	$0.45906
March 31, 2025	March 1, 2025	Feb. 28, 2025	$0.40568

Series E

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2024	March 1, 2024	Feb. 28, 2024	$0.43088
June 30, 2024	June 1, 2024	May 31, 2024	$0.43088
Sept. 30, 2024	Sept. 1, 2024	Aug. 31, 2024	$0.43088
Dec. 31, 2024	Dec. 1, 2024	Nov. 30, 2024	$0.43088
March 31, 2025	March 1, 2025	Feb. 28, 2025	$0.43088

Series G

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2024	March 1, 2024	Feb. 28, 2024	$0.31175
June 30, 2024	June 1, 2024	May 31, 2024	$0.31175
Sept. 30, 2024	Sept. 1, 2024	Aug. 31, 2024	$0.31175
Dec. 31, 2024	Dec. 1, 2024	Nov. 30, 2024	$0.42331
March 31, 2025	March 1, 2025	Feb. 28, 2025	$0.42331

Dividends are paid on the last day of the month in March, June, September and December. When a dividend payment date falls on a weekend or holiday, the payment is made on the following business day. Only dividend payments that have been approved by the Board of Directors are included in this table. The Board of Directors has also declared dividends on the Series I Preferred Shares, which are held by an affiliate of Brookfield Renewable Partners.

Voting Rights

Common shareholders receive one vote for each common share held.

Transfer Agent

Odyssey Trust Company
Trader's Bank Building,
702 - 67 Yonge Street,
Toronto, Ontario, M5E 1J8
Attention: Proxy Department

Phone

North America:
1-888-290-1175 toll-free

Outside North America:
1-587-885-0960

Fax

1-800-517-4553
Website:
www.odysseytrust.com

Exchanges

Toronto Stock Exchange (TSX)
New York Stock Exchange (NYSE)

Ticker Symbols

TransAlta Corporation common shares: TSX: TA, NYSE: TAC
TransAlta Corporation preferred shares: TSX: TA.PR.D, TA.PR.E, TA.PR.F, TA.PR.G, TA.PR.H, TA.PR.J

Additional Information

Requests can be directed to:

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Calgary/outside North America:
403.267.2520

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investor_relations@transalta.com
Website:
www.transalta.com

Shareholder Highlights

Ten-Year Total Shareholder Return vs. S&P/TSX Composite Index

Year ended Dec. 31 ($)	15	16	17	18	19	20	21	22	23	24
TransAlta	100	155	159	122	206	219	323	283	262	495
S&P/TSX	100	118	125	110	131	134	163	149	161	190

This chart compares what $100 invested in TransAlta and the S&P/TSX Composite Index at the end of 2015 would be worth today, assuming the reinvestment of all dividends.

Source: FactSet

Ten-Year Market Value vs. Book Value

Year ended Dec. 31 ($ per share)	15	16	17	18	19	20	21	22	23	24
Market value	4.91	7.43	7.45	5.59	9.28	9.67	14.05	12.11	11.02	20.33
Book value	8.52	8.92	8.28	7.16	7.14	5.13	2.37	0.62	2.16	2.66

Data is from 2014 onwards.

Source: FactSet and TransAlta

Monthly Volume and Market Prices

2024	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Volume (millions)	16	14	26	23	22	21	21	23	29	23	28	41
TSX closing price ($ per share)	9.74	9.31	8.69	9.13	9.79	9.70	10.40	11.87	14.02	14.56	15.87	20.33

Source: FactSet

Return on Common Shareholders' Equity

(%)	15	16	17	18	19	20	21	22	23	24
ROE	(1.2)	5.4	(10.0)	(15.8)	0.03	(30.3)	(116.6)	1.0	84.8	23.2

Source: TransAlta

Fighting Against Forced Labour and Child Labour in Supply Chains Act 2024 Annual Report

A. INTRODUCTION

TransAlta Corporation ("**TransAlta**") is subject to legal requirements in section 11 of the Canadian federal Fighting Against Forced Labour and Child Labour in Supply Chains Act (the "**Act**"). This Report is made pursuant to the Act for the financial year ending December 31, 2024 ("**Reporting Period**") and was approved by the TransAlta Board of Directors on February 18, 2025.

The Report is filed by TransAlta on behalf of itself and the following subsidiaries licensed to import goods into Canada: TransAlta Generation Partnership; TransAlta Energy Marking Corp.; TransAlta Cogeneration L.P.; Keephills 3 Limited Partnership; TransAlta (SC) L.P.; Melancthon Wolfe Wind L.P.; TA Alberta Hydro LP; and Garden Plain I LP. The terms the **"Company"**, **"TransAlta"**, **"we"**, **"our"**, or **"us"** refer to TransAlta Corporation and extend to all entities listed in this report.

The Report sets out the steps taken to prevent and reduce the risk that forced labour or child labour is used at any step of the production of goods in Canada or elsewhere by TransAlta or of goods imported into Canada by TransAlta.

On December 4, 2024, TransAlta successfully completed the acquisition of 100 percent of the shares in Heartland Generation Ltd. and Alberta Power (2000) Ltd. (collectively, **"Heartland"**) and commenced integration of Heartland's operations into our business.

Unless otherwise stated, the operational and supply chain data and content presented in the main body of the report does not include former Heartland entities. However, we have presented specific data and content for former Heartland entities in section 3 of this Report.

B. OVERVIEW

1. Steps to Prevent and Reduce Risks of Forced and Child Labour

TransAlta took significant steps during the Reporting Period to prevent and reduce the risk of forced labour or child labour in its business and supply chains, described below.

(a) Enhanced Supplier Risk Management

Throughout the Reporting Period, we prioritized actions to deepen our understanding of modern slavery risks within our operations and supply chains, enhancing the effectiveness of measures to address these risks. We proactively examined the upstream sourcing of materials, equipment and services from our key vendor partners to support both growth and operational needs.

(b) Expanded ESG Data Collection from Suppliers

We also implemented a modern slavery questionnaire for new suppliers to gather information on their policies and practices to mitigate modern slavery risks within their workplaces and supply chains. For existing suppliers, we distributed a modern slavery survey to collect insights on their operations, supply chains, and environmental and social impacts, with a specific focus on risks of modern slavery. This initiative was conducted across TransAlta.

(c) Employee Training Initiatives

We provided annual mandatory Code of Conduct training for all employees as well as specialized training on Canada's modern slavery legislation for employees involved in the procurement of goods and services. This training was designed to enhance awareness and understanding of responsible procurement practices among our teams.

These actions were applied broadly across TransAlta, except as otherwise noted.

C. TRANSALTA'S STRUCTURE, ACTIVITIES AND SUPPLY CHAINS

1. TransAlta Overview

TransAlta is the sole parent company of the entities covered in this Report and is headquartered in Calgary, Alberta. We have been engaged in the development, production, and sale of electric energy since 1911. We are one of Canada's largest independent power generators and among Canada's largest non-regulated electricity generation and energy marketing companies, with 9,014 megawatts ("**MW**") of gross installed capacity.

We own, operate, and manage a highly contracted and geographically diversified portfolio of assets using a broad range of technologies and fuels, including water, wind, solar, natural gas, energy storage, and coal. We are focused on generating and marketing electricity in Canada, the United States, and Western Australia through our diversified portfolio of facilities. Our mission is to provide safe, low-cost, and reliable clean electricity.

2. TransAlta's Supply Chains

During the Reporting Period, we procured goods and services globally from a network of approximately 2,000 suppliers and contractors across North America, Australia, Asia and Europe. Our suppliers range from major, Fortune 500 international companies to small, local businesses.

Our supply network largely reflects our operational footprint, meaning most of our direct spend during the Reporting Period continued to be in the countries where we have operated assets. Approximately 52 percent of our suppliers were based in Canada, 26 percent were located in the United States, 21 percent in Australia and approximately 1 percent in Europe or Asia. We appreciate, however, that some of these suppliers are supplying goods that originated from other jurisdictions. Our Supply Chain team endeavors to understand our vendors' partners upstream providers where possible.

Our suppliers cover a wide range of disciplines, including construction, engineering, and professional services. Approximately 80 percent of our 2024 spend was allocated to the procurement of fuel, professional services, local operations and maintenance services, as well as the local operations of wind turbines, conducted in both Canada and the United States.

We have a centralized Supply Chain Management ("**SCM**") function that serves the entire Company, including our Canadian, United States and Australian operations. This function is responsible for all aspects of SCM, including strategic sourcing, contract management, and supply chain and commercial risk management, all with the goal of creating maximum value for TransAlta and our shareholders while upholding the principles and standards set out in our Supplier Code.

3. Heartland's Supply Chains

On December 4, 2024, we completed the acquisition of Heartland and began integrating its operations and functions into our business - a process that will continue over time.

The former Heartland operations are generation assets in Alberta and British Columbia, Canada, consisting of 507 MW of cogeneration, 387 MW of contracted and merchant peaking generation, 950 MW of gas-fired thermal generation, transmission capacity.

Prior to acquisition, Heartland implemented a Code of Business Conduct and Ethics, including Code Policies (the "**Heartland Code**"), a Modern Slavery Policy, a Supply Chain Management Policy and Sourcing Practice, and an Ethics and Compliance Helpline (collectively, the "**Policies**"). Each employee was required to read and acknowledge the Heartland Code, which also references the Policies. Additionally, all third-party suppliers and contractors were obligated to adhere to these Policies as part of Heartland's standard supply chain contract terms.

During the Reporting Period, we were advised that Heartland conducted a risk analysis of its supply chains to assess potential forced labour and child labour risks. As part of this analysis, we understand that Heartland's key material suppliers and contractors were reviewed and sent a questionnaire requesting detailed information about their exposure to forced labour and child labour, as well as the actions they are taking to prevent and mitigate these risks. The results of the risk analysis and questionnaires were analyzed for any potential exposure, and no instances of forced labour or child labour were identified.

4. TransAlta's Policies and Due Diligence Processes

TransAlta recognizes that forced labour, child labour, and other forms of modern slavery are critical issues, and we stand strongly against this exploitation. TransAlta has accordingly developed internal governance documents that take into consideration supply chain and human rights compliance risks. Our supply chain processes are designed to procure goods and services that meet our standards for environmental stewardship, social responsibility, and ethical practices. We attain this objective by incorporating ESG factors into our supplier lifecycle management framework, encompassing supplier selection and relationship management through various means, including pre-qualification, requests for proposals, proposal evaluations, and contracts.

5. TransAlta Policies Addressing Forced and Child Labour

(a) Corporate Code of Conduct (the "**Code**")

TransAlta's Code sets out the expected behavior of all employees, including independent third-party contractors such as consultants, agents or independent contractors retained to do work or represent TransAlta's interests.

We are committed to creating a work environment where all employees feel safe and are valued for the diversity they bring to our business. We have continued to require employees to complete annual mandatory Code training. This training is reviewed and updated approximately each

year and is required to be completed by employees before completing the required annual Code acknowledgment and sign-off. In 2024, 100 percent of employees completed this training and acknowledged and signed-off on the Code. We do not tolerate discrimination or harassment and are committed to honoring domestic and internationally accepted labour standards and support the protection of human rights.

(b) Supplier Code of Conduct ("**Supplier Code**")

TransAlta expects suppliers to know and uphold the human rights of all workers, whether temporary or contract employees, and to treat all their workforce members with dignity and respect, providing them with safe working conditions. The Supplier Code specifically addresses the prohibition of human rights abuses, including all forms of forced labour and child labour.

We expect all our suppliers to adhere to and implement the principles and practices expressed in the Supplier Code. In addition, we expect suppliers to cascade these principles and requirements down to their own respective suppliers.

TransAlta encourages all suppliers, workers, and other stakeholders, through the provisions of the Supplier Code, to speak up about any issues, concerns, and suspected violations of TransAlta's policies. All ethical or legal concerns related to the Supplier Code can be reported to TransAlta's Ethics Help Line, which is set out in more detail below.

(c) Human Rights and Discrimination Policy

TransAlta's Human Rights and Discrimination Policy is a global policy that communicates our commitment to human rights in our operations and supply chains. This commitment includes that TransAlta will strive to ensure our operations do not negatively impact human rights of local communities, which is done through meaningful and transparent consultations with stakeholders who are or will be potentially affected by our operations. TransAlta employees will not be complicit in human rights abuses.

The policy states that TransAlta's personnel policies and practices in our operations around the world will respect the following fundamental rights:

- the right to a healthy and safe workplace;
- the right to non-discrimination in the workplace;
- the right to be free from cruel and unusual disciplinary practices;
- the prohibition of exploitative child labour; and
- the prohibition of forced labour and the avoidance of products produced by such labour.

(d) Procurement Policy

TransAlta is committed to upholding our Procurement Policy, which aims to maintain workplaces that strictly prohibit all forms of forced labour.

(e) Whistleblower Policy and Ethics Helpline

Our Whistleblower Policy offers a reporting mechanism for our employees, officers, directors, and contractors to report ethical or legal violations, among other concerns. Stakeholders may make a report to identify individuals within TransAlta or through the Company's third-party Ethics Helpline. The Ethics Helpline is a confidential and anonymous platform, which can be accessed 24 hours a day, 356 days a year by phone, mail, or electronically.

Upon receipt of a report, TransAlta will review the facts, and determine whether sufficient facts are present to initiate an investigation. Upon completion of an investigation, we seek to address potential impropriety promptly and/or establish a corrective action plan in collaboration with relevant stakeholders. Our Whistleblower Policy prohibits retribution against any individual who reports an ethical complaint.

(f) Due Diligence Processes

We developed a multi-year roadmap to further integrate additional ESG considerations and opportunities, including the promotion and protection of human rights, into our SCM strategies and programs. This includes thorough pre-screening, self-assessment questionnaires, on-site and desktop evaluations, and ongoing performance monitoring, each of which is set out in more detail below.

(g) Pre-screening and Self-Assessment

We engage internal subject-matter experts, including sustainability and legal, to provide input into supplier pre-qualification and the monitoring phases of the supplier lifecycle, as well as to offer guidance on emerging issues. Our aim is to ensure that our standards regarding safety, human rights, sustainability, and environmental practices are upheld throughout our supply chains, and that suppliers follow the high standards set forth in the Supplier Code.

(h) Requests for Proposals ("**RFPs**") and Proposal Evaluations

Following a risk-based assessment of our supplier base, we may include in our RFPs specific questions regarding goods and services associated with medium or high levels of risk. These questions address the origins of critical materials and components, supplier location, ownership, scope of business, etc. In certain instances, we may seek explicit assurances concerning specific risk areas and

require proponents to affirm their commitment to specific contractual terms addressing these concerns.

(i) Contractual Measures

TransAlta's contracts include appropriate verification, notification requirements, audit, and inspection clauses, and we reserve the right to conduct inspections, assessments and audits to ensure that suppliers comply with applicable laws, rules, and standards, including those related to human rights. In addition, our standard terms require suppliers to commit to adhering to the principles and standards in our Supplier Code and to requiring their own suppliers to commit to similar principles and standards. TransAlta also reserves the right to discontinue business relationships in cases of non-adherence to the Supplier Code.

Our suppliers are obligated to take reasonable steps to ensure that goods and services are procured from ethical sources. This includes refraining from benefiting, directly or indirectly, from child or forced labour or any other discriminatory work practices.

Furthermore, TransAlta may request that a supplier provides information about its corporate structure (including relevant subcontractors), its policies (including those related to forced labour and child labour), and the steps the supplier has taken to assess, manage, remediate, or provide training in regard to the principles and requirements covered by the Supplier Code.

(j) Ongoing Monitoring

Compliance monitoring is a central focus for TransAlta. In line with a risk-based approach, we may initiate periodic reassessments linked to contract renewals or anniversaries.

We are committed to continually enhancing various measures, including the terms outlined in our suppliers' contracts, alongside proactive monitoring of diverse information sources, such as the Uyghur Forced Labour Prevention Act Entity List, Global Affairs Canada advisories, industry group updates, and non-governmental organization websites to identify suppliers at risk.

6. Risks in TransAlta's Operations and Supply Chains

(a) TransAlta's Operations

We have assessed the risk of forced labour or child labour in our operations to be low for the following reasons:

- TransAlta's workforce exists only within Canada, the United States, and Australia, which have comprehensive and robust labour, employment, and human rights laws.
- All site operational and office staff are hired in accordance with the laws and regulations in the jurisdictions where we operate.
- During the onboarding process, we conduct checks related to the right to work and ensure that individuals are choosing to work of their own free will.
- A portion of our workforce is represented by strong prominent labour unions.
- All staff have the freedom to join a trade union or other association.
- TransAlta benchmarks all the roles against three different remuneration surveys.

(b) TransAlta's Supply Chains

For TransAlta, our supply chains, organizations that provide goods or services, play a key role in our ability to satisfy our social responsibility commitments and sustainability objectives. We strive to work with suppliers who are leaders in their industries, adhere to our fundamental policies and procedures, and share our commitment to meet the highest standards relating to human rights.

Like many entities operating within the energy sector, and particularly the renewable energy space, we recognize risks of forced labour and child labour may exist in our supply chains. As outlined by the United Nations Guiding Principles on Business and Human Rights, our primary exposure to forced labour is expected to be beyond the second tier[1] of our third-party relationships rather than direct causative impacts or contributory actions of our business.

This is particularly relevant in the following higher-risk sectors and products:

- solar panels;
- battery energy storage equipment;
- wind turbines;
- engineered equipment;
- information and communications technologies;
- industrial consumables;
- electronics and electrical hardware; and
- freight services.

During the Reporting Period, TransAlta has not identified any instances of modern slavery or child labour in its supply chains or operations. No remedial steps have been deemed necessary at this time, including related to remediation of income loss to the most vulnerable families that results from remediation measures.

C. STEPS TO MANAGE AND ASSESS RISK

1. TransAlta's Operations

TransAlta is dedicated to fostering a work environment where all employees feel secure and are valued. TransAlta's Code outlines the expected behavior of individuals doing work for TransAlta. Employees are required on an annual basis to complete mandatory Code training and to acknowledge in writing its requirements. This training was updated and provided to employees during the Reporting Period.

2. TransAlta's Supply Chains

We have taken proactive steps to enhance supplier risk identification, assessment, analysis, remediation, and monitoring. We risk map of our supplier base to evaluate critical suppliers, group and prioritize them, identify potential vulnerabilities, and assess controls in place. We examine the geographic location of suppliers, differentiating between Organization for Economic Cooperation and Development (OECD) and non-OECD regions, complexity of their supply chains, especially those leading to areas known for forced or child labour, industry-specific risks linked to human rights and labour practices, the critical or unique nature of the products procured versus commodity items, the duration of the supply relationships, and overall spend.

Following the risk mapping, assessment, and analysis, no instances of forced labour or child labour were identified during the Reporting Period. However, we have classified certain goods and services as medium risk, such as transformers, due to their manufacturing origin in China, and freight services, given the inherent risk for some modern slavery practices within the shipping industry. That said, we predominantly procure freight services from low-risk jurisdictions. We are also aware of the elevated risks of forced and child labour associated with certain renewable energy technologies, such as wind turbines, solar panels, and batteries. However, no such goods were purchased during the Reporting Period.

Certain manufacturing regions and materials carry a higher risk of forced labour due to its prevalence in specific countries. We understand that many of our direct suppliers rely on global supply chains to provide goods and services to us, which presents challenges in obtaining visibility beyond the first tier.[1] As a whole, considering the factors and processes set out above, we view the risks of forced labour or child labour in our supply chains as low.

3. Employee Training

In addition to annual, mandatory Code training during the Reporting Period, we successfully developed and delivered mandatory employee training on forced labour and child labour to all employees involved in the procurement of goods and services. This training covered essential aspects of responsible procurement and sustainability-focused supplier management, including recognizing indicators of human trafficking behaviors. Participants explored the concept of forced labour in depth, examined international treaties and definitions, and learned about key indicators and "hot geographies" where forced labour is more prevalent. The training also addressed reporting legislation, trade and government contracting prohibitions, the role of the Canadian Ombudsperson for Responsible Enterprise, as well as potential litigation and reputational risks.

Through practical applications, the training equipped TransAlta employees with the necessary tools and awareness to promote responsible procurement practices, fostering a culture of ethical and sustainable sourcing within the organization.

D. ASSESSING EFFECTIVENESS OF OUR ACTIONS

TransAlta understands that it has a responsibility to assess and mitigate the risks of modern slavery in its operations and supply chains over the long term. The Board has overall responsibility for the strategy around modern slavery. It has delegated to the Governance, Safety and Sustainability Committee the development of strategies, policies and practices to create value consistent with the long-term preservation and enhancement of shareholder value and social wellbeing, including human rights, working conditions and responsible sourcing.

We are committed to continuously enhancing our program to identify, assess, and manage modern slavery risks in our operations and supply chains. When evaluating the immediate effectiveness of our modern slavery program, we focus on reviewing the operation of existing processes and systems, identifying gaps or opportunities to refine our approach, and designing and implementing improvements to address identified issues.

(1) Tier Two: supp ier of goods or services directly to Tier One supp iers. Tier Two suppliers are subcontractors who may not have a direct relationship with the client company. Tier Three: supp iers of raw material or base product to Tier Two supp iers. Tier Three supp iers may, for example, provide minerals for the manufacture of products by Tier Two suppliers.

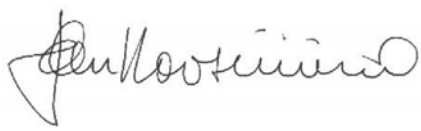
During the course of 2025, we plan to:

1. Continue reviewing and analyzing ESG data from our supplier network, with a focus on gaining deeper insights into the upstream sourcing of materials, equipment, and services provided by our key vendor partners to support both growth and operations.
2. Establish a vendor management database to formally record the assessment of modern slavery risk and commitment to the Supplier Code by our suppliers.
3. Continue to enhance our internal due diligence tools and processes, including, but not limited to, updating our Vendor Onboarding Questionnaire forms.
4. Advance the integration of Heartland into TransAlta's compliance framework.
5. These improvements will further advance our efforts to prevent and reduce the risk of forced labour and child labour in our business and supply chains, aligning with our mission to uphold the highest standards of ethical and responsible business practices.

E. CONSULTATION AND APPROVAL

In accordance with the Act, specifically section 11 thereof, I attest I have reviewed the information contained in the Report for the TransAlta entities listed above. Based on my knowledge and having exercised reasonable diligence, I attest that the information in the Report is true, accurate and complete in material respects for the purposes of the Act, for the reporting year listed above.

I have the authority to bind TransAlta Corporation.



Full name: John H. Kousinioris
Title: President and Chief Executive Officer
Date: Feb. 19, 2025

Corporate Information

Corporate Governance: New York Stock Exchange Disclosure Differences

TransAlta's Corporate Governance Guidelines, Board Charter, Committee Charters, position descriptions for the Chair and President & CEO, and codes of business conduct and ethics are available on our website at www.transalta.com. Also available on our website is a summary of the significant ways in which TransAlta's corporate governance practices differ from those required to be followed by US domestic companies under the New York Stock Exchange's listing standards. Currently there are no significant differences between our governance practices and those of the New York Stock Exchange.

Ethics Helpline

The Board of Directors has established an anonymous and confidential Internet portal, email address and toll-free telephone number for employees, contractors, shareholders and other stakeholders who wish to report accounting irregularities, ethical violations or any other matters they wish to bring to the attention of the Board.

The Ethics Helpline phone number is **1.855.374.3801** (US/Canada) and **1.800.40.5308** (Australia)

Internet portal: **transalta.com/ethics-helpline**

Email: **ethics_helpline@transalta.com**

Any communications to the Board of Directors may also be sent to **corporate_secretary@transalta.com**.

TransAlta Corporate Officers

John Kousinioris
President and Chief Executive Officer

Joel Hunter
Executive Vice President, Finance and Chief Financial Officer

Nancy Brennan
Executive Vice President, Legal and External Affairs

Jane Fedoretz
Executive Vice President, People, Culture and Chief Administrative Officer

Mark Flickinger
Executive Vice President, Project Delivery and Construction

Chris Fralick
Executive Vice President, Generation

Kerry O'Reilly Wilks
Executive Vice President, Growth and Energy Marketing

Blain van Melle
Executive Vice President, Commercial and Customer Relations

David Little
Senior Vice President, Growth

Michelle Cameron
Vice President and Corporate Controller

Jon Ozirny
Vice President, Legal and Corporate Secretary

Glossary of Key Terms

Alberta Electric System Operator (AESO)

Alberta Electric System Operator; the independent system operator and regulatory authority for the Alberta Interconnected Electric System.

Alberta Hydro Assets

The Company's hydroelectric assets owned through a wholly owned subsidiary, TA Alberta Hydro LP. These assets are located in Alberta and consist of the Barrier, Bearspaw, Bighorn, Brazeau, Cascade, Ghost, Horseshoe, Interlakes, Kananaskis, Pocaterra, Rundle, Spray and Three Sisters hydro facilities.

Alberta Thermal

The business segment previously disclosed as Canadian Coal has been renamed to reflect the ongoing conversion of the boilers to burn gas in place of coal. The segment includes the legacy and converted generating units at our Sundance and Keephills sites and includes the Highvale mine.

Ancillary Services

As defined by the Electric Utilities Act, ancillary services are those services required to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency.

Automatic Share Purchase Plan (ASPP)

The ASPP is intended to facilitate repurchases of common shares under the NCIB, including at times when the Company would ordinarily not be permitted to make purchases due to regulatory restrictions or self-imposed blackout periods.

Availability

A measure of time, expressed as a percentage of continuous operation - 24 hours a day, 365 days a year - that a generating unit is capable of generating electricity, regardless of whether or not it is actually generating electricity.

Balancing Pool

The Balancing Pool was established in 1999 by the Government of Alberta to help manage the transition to competition in Alberta's electric industry. Their current obligations and responsibilities are governed by the Electric Utilities Act (effective June 1, 2003) and the Balancing Pool Regulation. For more information go to www.balancingpool.ca.

Capacity

The rated, continuous load-carrying ability of generation equipment, expressed in megawatts.

Cash-Generating Unit (CGU)

A cash-generating unit is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets, and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose.

Centralia

The business segment previously disclosed as US Coal has been renamed to reflect the sole asset.

Cogeneration

A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating or cooling purposes.

Disclosure Controls and Procedures (DC&P)

Refers to controls and other procedures designed to ensure that information required to be disclosed in the reports filed by the Company or submitted under securities legislation is recorded, processed, summarized and reported within the time frame specified in applicable securities legislation. DC&P include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in its reports that it files or submits under applicable securities legislation is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Dispatch Optimization

Purchasing power to fulfil contractual obligations, when economical.

Economic Dispatch

Purchasing power to fulfil contractual obligations, when economical.

Emissions Performance Standards (EPS)

Under the Government of Ontario, emission performance standards establish greenhouse gas (GHG) emissions limits for covered facilities.

Environmental Management Systems (EMS)

A set of processes and practices that enable an organization to reduce its environmental impacts and increase its operating efficiency.

Exchangeable Debentures

On May 1, 2019, Brookfield invested $350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039.

Exchangeable Preferred Shares

On Oct. 30, 2020, Brookfield invested $400 million in the Company in exchange for redeemable, retractable first preferred shares (Series I). The Series I Preferred Shares are accounted for as current debt and the exchangeable preferred share dividends are reported as interest expense.

Exchangeable Securities

On March 22, 2019, the Company entered into an Investment Agreement whereby Brookfield Renewable Partners or its affiliates (collectively "Brookfield") agreed to invest $750 million in TransAlta through the purchase of exchangeable securities, which are exchangeable into an equity ownership interest in TransAlta's Alberta hydro assets in the future at a value based on a multiple of the Alberta hydro assets' future-adjusted EBITDA (Option to Exchange).

Force Majeure

Literally means "greater force." A clause in a contract that excuses a party from liability if some unforeseen event beyond the control of that party prevents it from performing its obligations under the contract.

Free Cash Flow (FCF)

Amount of cash generated by the Company through its operations (cash from operations) minus the funds used by the Company for the purchase, improvement or maintenance of the long-term assets to improve the efficiency or capacity of the Company (capital expenditures).

Funds from Operations (FFO)

Calculated as cash flow from operating activities before changes in working capital and is adjusted for transactions and amounts that the Company believes are not representative of ongoing cash flows from operations.

Gigajoule (GJ)

A metric unit of energy commonly used in the energy industry. One GJ equals 947,817 British thermal units (Btu). One GJ is also equal to 277.8 kilowatt hours.

Gigawatt (GW)

A measure of electric power equal to 1,000 megawatts.

Gigawatt Hour (GWh)

A measure of electricity consumption equivalent to the use of 1,000 megawatts of power over a period of one hour.

Global Reporting Initiative (GRI)

An independent not-for-profit organization that leads a global multi-stakeholder process to develop and refine rigorous yet practical sustainability reporting.

Greenhouse Gas (GHG)

A gas that has the potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons and perfluorocarbons.

Heartland Credit Facilities

As part of the Heartland acquisition on Dec. 4, 2024, the Company assumed a $232 million drawn term facility and a $25 million revolving facility with a syndicate of banks, (collectively Heartland Credit Facilities). At Dec. 31, 2024 the drawn term facility was $224 million. The $25 million revolving facility is undrawn and available for working capital and general corporate purposes.

ICFR

Internal control over financial reporting.

IFRS

International Financial Reporting Standards.

Megawatt (MW)

A measure of electric power equal to 1,000,000 watts.

Megawatt Hour (MWh)

A measure of electricity consumption equivalent to the use of 1,000,000 watts of power over a period of one hour.

Merchant

A term used to describe assets that are not contracted and are exposed to market pricing.

NCIB

Normal Course Issuer Bid.

OM&A

Operations, maintenance and administration costs.

Other Hydro Assets

The Company's hydroelectric assets located in British Columbia and Ontario and assets owned by TransAlta Renewables, which include the Taylor, Belly River, Waterton, St. Mary, Upper Mamquam, Pingston, Bone Creek, Akolkolex, Ragged Chute, Misema, Galetta, Appleton and Moose Rapids facilities.

Planned Divestitures

Poplar Hill and Rainbow Lake facilities, which the Company agreed to divest pursuant to a consent agreement entered into with the Commissioner of Competition for Canada following closing of the acquisition of Heartland Generation Ltd. and certain affiliates.

Planned Outage

Periodic planned shutdown of a generating unit for major maintenance and repairs. Duration is normally in weeks. The time is measured from unit shutdown to putting the unit back online.

Power Purchase Agreement (PPA)

A long-term agreement established by regulation for the sale of electric energy to PPA buyers.

PP&E

Property, plant and equipment.

Renewable Energy Credits (REC)

All right, title, interest and benefit in and to any credit, reduction right, offset, allocated pollution right, emission reduction allowance, renewable attribute or other proprietary or contractual right, whether or not tradable, resulting from the actual or assumed displacement or reduction of emissions, or other environmental characteristic, from the production of one MWh of electrical energy from a facility utilizing certified renewable energy technology.

Renewable Power

Power generated from renewable terrestrial mechanisms including wind, geothermal, solar and biomass with regeneration.

Sustainability Accounting Standards Board (SASB)

Connects businesses and investors on the financial impacts of sustainability. SASB Standards identify the subset of ESG issues most relevant to financial performance in each of the 77 covered industries.

TA Cogen

The Company owns 50.01 per cent in TransAlta Cogeneration, L.P. (“TA Cogen”), which owns, operates or has an interest in a portfolio of cogeneration facilities, including three natural-gas-fired cogeneration facilities (Ottawa, Windsor and Fort Saskatchewan) and a natural-gas-fired facility (Sheerness).

Term Facility

The $400 million term facility with our banking syndicate, which matures on Sept. 7, 2025, with floating interest rates that vary depending on the option selected (e.g. Canadian prime and bankers' acceptances).

Task Force on Climate-Related Financial Disclosures (TCFD)

Designed to solicit consistent, decision-useful, forward-looking information on the material

financial impacts on climate-related risks and opportunities, including those related to the global transition to a low-carbon economy. They are adopted by all organizations with public debt or equity in G20 jurisdictions for use in mainstream financial filings.

Taskforce on Nature-related Financial Disclosures (TNFD)

Market-led, science-based and government-backed initiative providing organizations with the tools to act on evolving nature-related issues.

Total Recordable Injury Frequency (TRIF)

Tracks the number of more serious injuries and excludes minor first aids, relative to exposure hours worked.

Turbine

A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction or a mixture of the two.

Turnaround

Periodic planned shutdown of a generating unit for major maintenance and repairs. Duration is normally in weeks. The time is measured from unit shutdown to putting the unit back online.

Unplanned Outage

The shutdown of a generating unit due to an unanticipated breakdown.

UN Sustainable Development Goals (SDGs)

Adopted by the United Nations in 2015 as a universal call to action to end poverty, protect the planet, and ensure that by 2030 all people enjoy peace and prosperity. The 17 SDGs are integrated—they recognize that action in one area will affect outcomes in others, and that development must balance social, economic and environmental sustainability.

Value at Risk (VaR)

A measure used to manage exposure to market risk from commodity risk management activities.



TransAlta Corporation

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-116:
Nat'l Park Serv. Testimony at BART Hearing re Centralia (2009)

Statement of the National Park Service
Before
The Washington Department of Ecology
Regarding
The Trans Alta Centralia Power Plant

October 13, 2009

Good evening. I am Randy King, Acting Superintendent of Mount Rainier National Park. I appreciate this opportunity to present comments of the National Park Service on the proposed consent decree addressing best available retrofit technology (BART) emissions reductions at the Centralia facility.

The Centralia facility is located in proximity to majestic national parks and wilderness areas whose resources are significantly affected by its nitrogen oxides emissions. Mount Rainer National Park – established by the citizens of Washington in 1899 as the Nation's fifth national park—is about 50 miles away. Emissions from the Centralia facility also impact Olympic and North Cascades National Parks, and I am also speaking this evening of behalf of Superintendent Karen Gustin of Olympic National Park, and Superintendent Chip Jenkins of North Cascades National Park.

By law, our Nation strives to "conserve unimpaired" national parks and wilderness areas, "in their natural state," protected from the adverse impacts of air pollution.

In 1995, we testified regarding the need for strong limits on emissions of sulfur dioxide at the Centralia facility to address the visibility impairment and other environmental concerns at the park and in the region caused by those emissions. We note with appreciation that since those strong emissions limits were put in place and the facility came into compliance, there has been a dramatic reduction in measured sulfate at Mount Rainier and a corresponding, statistically significant improvement in visibility on the twenty percent worst visibility days measured at the park. Today we note that the proposed consent decree does not require the best technology to reduce emissions of nitrogen oxides, also a key component of visibility impairment at the parks. Our review of the technical support documents

provided by the State concludes that applying the best technology to reduce nitrogen oxides (i.e., selective catalytic reduction technology) is both technically feasible and the most cost-effective option when considering the visibility improvement that would occur at Mount Rainier, Olympic, and North Cascades National Parks, and nine other Class I wilderness areas administered by the U.S. Forest Service. We are also concerned that the consent decree, which addresses the BART component of the Environmental Protection Agency's 1999 Regional Haze Rules, was negotiated without participation by the federal land managers. Since BART is a critical element of the State Implementation Plan for visibility protection, it is uncertain if the State's consent decree process met the requirements and spirit of the federal land manager consultation provisions of the Clean Air Act.

On June 24, 2009, the Department of the Interior was petitioned by the National Parks Conservation Association, Washington Wildlife Federation, Sierra Club, and Northwest Environmental Defense Center, to certify that emissions of nitrogen oxides from the Centralia facility are reasonably anticipated to cause or contribute to visibility impairment at Mount Rainier and Olympic National Parks. Such a certification would also require the State to specify BART for Centralia to address any reasonably attributable impairment under existing provisions of the State Implementation Plan. The Department of the Interior's initial response to the petitioners expressed the hope that the State's actions on BART for regional haze would address any concerns for reasonably attributable impacts. The consent decree as proposed does not adequately address these impacts. The Department of the Interior will make a final decision regarding the petition pending the outcome of the Department of Ecology's actions for regional haze BART.

To remedy our concerns with the BART limits established in the consent decree, we request that the Department of Ecology take a strong leadership role similar to its sulfur dioxide actions in 1995, and incorporate a BART requirement for selective catalytic reduction technology in the regional haze State Implementation Plan requirements for Centralia. This would limit Centralia's emissions of nitrogen oxides to approximately 3,000 tons per year, or approximately 12,000 tons per year less than that proposed in the consent decree.

Like the reduction in sulfur oxides clearly indicated, such a reduction of nitrogen oxides would lead to a direct improvement in visibility at Mount Rainier National Park, as well as contribute to improved visibility and decreased health effects from fine particulate matter region-wide. While the focus of our concern is the nitrogen oxide emissions, we are also concerned with mercury deposition at Mount Rainer and throughout the region. We note that addition of selective catalytic reduction technology, if appropriately designed, would be compatible with emissions reductions of mercury and would not interfere with future mercury emissions removal, should pending new regulations from EPA require more reduction than the co-benefit resulting from sulfur dioxide scrubbing and selective catalytic reduction.

In closing, I would like you to think about the importance of Mount Rainier National Park to this region and the world, for today's public and for future generations. There are many reasons that the law mandates our highest levels of environmental protection for these special areas. National parks and wilderness areas are our natural and cultural heritage. Sociology studies confirm their importance, as do our individual experiences of recreation and renewal. Over 1.1 million people visited Mount Rainier National Park in 2008 to recreate and visitation as of the end of August of this year is already above the 1 million mark.

Regarding the economic benefits of the park, for example, in 2001 when our last visitor survey was conducted, we learned that recreation visitors to Mount Rainier National Park spent $29.8 million within a 30 mile radius of the park. The total economic impact of visitor spending was $24 million in direct sales, $9 million in personal income, $13 million in direct value added and 649 jobs. With multiplier effects, created by the re-circulation of the money spent by tourists, visitor spending generated about $35 million in local sales, and an associated $13 million in personal income, $20 million in value added and 812 jobs. These figures do not include park admission fees or the impacts of the NPS payroll and operations in the area.[1]

[1] 3.3 million recreational visitors to Olympic NP spent $90 million within the Olympic Peninsula in 2000. The total economic impact of visitor spending was $71 million in direct sales, $29 million in personal income, $45 million in direct value added and 1,881 jobs. With multiplier effects, created by the re-circulation of the money spent by tourists, visitor spending generated about $100 million in local sales, and an associated $39 million in personal income, $62 million in value added and 2,290 jobs.

National parks and wilderness areas not only guard the natural and cultural assets of our Nation, but they are also our most sensitive gauges of environmental stewardship. Harm to these resources that our nation strives hardest to protect must signal an alarm for other resources and for us. The National Park Services' desired outcome in this process is a solution and a decision that protects air and other important resources by using proven, cost effective technologies to significantly reduce nitrogen emissions from the Centralia facility. To be clear, an outcome the National Park Service does not seek is the closure of the Centralia Power Plant. Experience from other states, and the success of the 1995 collaborative effort in reducing sulfur dioxide emissions from plant, tells us that these two outcomes – achieving a significant reduction in nitrogen emissions and keeping an important facility operating - are wholly compatible. We stand ready to work with all interested parties toward these outcomes.

This concludes my testimony. The National Park Service will be submitting detailed technical comments on the consent decree before the close of the public comment period.

Thank you.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-117:
Sierra Club Comments on TransAlta-Ecology Proposed BART Settlement (Nov. 2009)

EARTHJUSTICE

ALASKA CALIFORNIA FLORIDA MID-PACIFIC NORTHEAST NORTHERN ROCKIES
NORTHWEST ROCKY MOUNTAIN WASHINGTON, DC INTERNATIONAL

November 9, 2009

Via Electronic Mail

Sarah Rees
Washington Department of Ecology
Air Quality Program
P.O. Box 47600
Lacey, WA 98504-7600

Re: Proposed Ecology/TransAlta Settlement Agreement and Consent Decree
TransAlta Centralia Generation, L.L.C., Centralia, Washington

Dear Ms. Rees:

Earthjustice submits these comments on the proposed Settlement Agreement and Consent Decree regarding the coal-fired power plant in Centralia, Washington, between the State of Washington, Department of Ecology ("Ecology") and TransAlta Centralia Generation, L.L.C. ("TransAlta"). These comments are submitted on behalf of the National Parks Conservation Association, the Sierra Club, and Northwest Environmental Defense Center (collectively the "Conservation Organizations").[1]

The National Parks Conservation Association ("NPCA") is a national organization whose mission is to protect and enhance America's National Parks for present and future generations. NPCA performs its work through advocacy and education. NPCA has over 310,000 members nationwide with its main office in Washington, D.C. and 24 regional and field offices. NPCA's regional Northwest office is located in Seattle, where it works on a variety of issues affecting Northwest National Parks such as Mt. Rainier, Olympic, and North Cascades National Parks. NPCA is active in advocating for strong air quality requirements in our parks, including submission of petitions and comments relating to visibility issues, regional haze State Implementation Plans, global warming and mercury impacts on parks, and emissions from individual power plants and other sources of pollutants affecting National Parks. NPCA's members live, work, and recreate in all the National Parks of the Northwest, including those directly affected by the TransAlta coal-fired power plant in Centralia, Washington.

The Sierra Club is a national organization founded in 1892, with more than 60 chapters throughout the U.S., including the Cascade Chapter located in Seattle, Washington. The Cascade Chapter's membership resides and recreates throughout the state. Sierra Club is devoted to the

[1] The Conservation Organizations, with the Washington Wildlife Federation, also filed a Petition to the U.S. Department of Interior, National Park Service, requesting certification to Ecology that visibility impairment in Mt. Rainier and Olympic National Parks is reasonably attributable to nitrogen oxide emissions from the TransAlta Centralia coal plant. The petition is pending.

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study and protection of the earth's scenic and ecological resources—mountains, wetlands, woodlands, wild shores and rivers, deserts, plains, and their wild flora and fauna. An important part of Sierra Club's current work at both the national and chapter level, is its Beyond Coal campaign which, among other things, focuses on retiring and reforming old coal-fired power plants that are significant contributors to health-harming soot and smog pollution, global warming pollutants, and hazardous pollutants such as mercury.

The Northwest Environmental Defense Center ("NEDC") is a regional non-profit organization, based in Portland, Oregon. NEDC works to protect the environment and natural resources of the Pacific Northwest, by providing legal support to individuals and grassroots organizations with environmental concerns, and engaging in litigation independently or in conjunction with other environmental groups. NEDC also provides hands-on experience for students to enhance their education in environmental law. NEDC is regularly involved in efforts to maintain or enhance the air quality of the Pacific Northwest by serving as a watchdog over Oregon's Department of Environmental Quality, Washington's Department of Ecology, and each state's respective permitting processes. Student volunteers regularly comment on proposals for new air permits and permit modifications, monitor current permits in search of violations, and monitor major air quality issues, such as changes in administrative regulations.

The Conservation Organizations object to the Settlement Agreement and Consent Decree (the "Agreement") as contrary to the law, not supported by the record or established engineering and science, and because the Agreement is contrary to the public interest.

I. THE NITROGEN OXIDE PROVISIONS OF THE AGREEMENT DO NOT COMPLY WITH THE REQUIREMENTS OF THE CLEAN AIR ACT AND ARE INADEQUATE TO CLEAN UP AND PROTECT THE AIR QUALITY OF WASHINGTON'S NATIONAL PARKS AND WILDERNESS AREAS.

A. Nitrogen Oxide Pollutants From The TransAlta Coal Plant Negatively Affect the Air Quality Of at Least Twelve Class I Areas

On an annual basis, the TransAlta Coal Plant in Centralia, Washington (hereinafter the "TransAlta coal plant") discharges approximately 12,000-16,000 tons of nitrogen oxides ("NOx").[2] NOx is a primary contributor to haze pollution. Haze pollution is adversely affecting the air quality in many of the region's national parks and wilderness areas.[3] The Clean Air Act

[2] EPA emissions database http://camddataandmaps.epa.gov/gdm/index.cfm.

[3] See enclosed extinction analyses and conclusions from National Park Service demonstrating TransAlta coal plant's NOx emissions will be an increasing source of haze pollution in Washington's Class I areas and which provide: "NO_X emissions from Centralia in 2002 were approximately 15,470 tons or approximately 36 percent of all point source NO_X emissions in the State. Based on [Western Regional Air Partnership] WRAP projections, Centralia will be approximately 10 percent of ALL mobile and point source emissions in the State by 2018. 2018 Projections: Nitrate will become more important than sulfate for extinction at Olympic and

("CAA") requires that national parks and wilderness areas, identified in the CAA as "Class I areas," must receive the highest degree of protection from all air pollution. 42 U.S.C. § 7472.

Almost twenty-five years ago, in 1985, the Department of the Interior ("Interior") certified to the Environmental Protection Agency ("EPA") that visibility in Mt. Rainier and Olympic National Parks, as well as all other Class I areas in the region, was impaired. Almost fifteen years ago, in 1995, the National Park Service ("NPS") formally notified the Southwest Air Pollution Control Authority (now known as the Southwest Clean Air Agency or "SWCAA") and Ecology that the impairment of visibility in Class I areas in Washington could reasonably be attributable to sulfur dioxide emissions from the coal plant in Centralia.[4]

The TransAlta coal plant currently employs a combustion control technology commonly-referred to as "Lo-Nox burners" (or "LNC3") to control haze-causing NOx pollutants.[5] At this level of control, the TransAlta coal plant is impairing visibility in at least twelve Class I areas in the region, the second largest cumulative impact of any coal-fired power plant in the nation.[6] According to EPA's Clean Air Markets Database, in 2007, the TransAlta coal plant was in the top 10 percent of worst polluters for NOx.

The CAA requires the clean-up of visibility pollution at Mt. Rainier and Olympic National Parks (as well as all other Class I areas in the region). 42 U.S.C. § 7491(a)(1). Despite some improvements in the TransAlta coal plant's emissions, the air quality at Mt. Rainier and Olympic National Parks, and other Class I areas remains impaired, with haze pollution still primarily caused by the TransAlta coal plant.[7] As part of the requirements to clean-up and protect Class I areas, the CAA and EPA regulations and guidance require states to develop a State Implementation Plan ("SIP") for addressing visibility impairment, 42 U.S.C. § 7491(b)(2) and 40 C.F.R. § 51.302, and as part of that SIP, to ensure that certain major sources of air pollutants, such as the TransAlta coal plant, employ Best Available Retrofit Technology ("BART") to control pollutants that cause or contribute to haze pollution, including NOx. Id. The critical aspect of the visibility protection program is the requirement for each applicable implementation plan in which Class I areas are located to contain "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal. The SIP and the BART determinations within it are subject to public process and the states must consult with the Federal Land Managers ("FLMs") as part of the process. 42 U.S.C. §§ 7410 and 7491.

Mount Rainier according to the WRAP projections."

[4] See letters dated August 2, 1995 and October 16, 1995, enclosed with these comments.

[5] See Report of Dr. Ranajit Sahu, November 4, 2009, enclosed and incorporated herein.

[6] See enclosed graphs and material from NPS and TransAlta's own extinction analyses in Ecology's files.

[7] See Testimony of Mt. Rainier Acting Superintendent Randy King, October 13, 2009, copy enclosed.

To determine what constitutes BART for a source, Washington must employ a five-step process:

1. Identify all available retrofit control technologies;
2. Eliminate technically infeasible control technologies;
3. Evaluate the control effectiveness of remaining control technologies;
4. Evaluate impacts and document the results;
5. Evaluate visibility impacts.

Appendix Y to C.F.R. Part 51, Guidelines for BART Determinations Under the Regional Haze Rule, Section IV. See also 40 C.F.R. § 51.301 and 42 U.S.C. § 7491(g)(2).[8]

The proposed Agreement fails to conform to these BART requirements and processes.

B. The Flex Fuels Project Can Not Properly Be Considered BART.

The Agreement suggests that the TransAlta Coal Plant will be implementing "additional" NOx controls through the "Flex Fuels" project. Conservation Organizations disagree that the Flex Fuels project is an additional NOx control, or a NOx control that can be considered BART.

1. Flex Fuels is not a NOx reduction technology or project.

It is clear from the record that TransAlta has planned and implemented (and would have implemented regardless of any mediated agreement with Ecology), the Flex Fuels project over the course of the last several years.[9] It has been TransAlta's plan and intent for years to move away from burning Centralia coal to the exclusive use of Powder River Basin ("PRB") coal. Flex Fuels is a boiler efficiency project associated with the shift to PRB coal. Specifically, TransAlta, contrary to earlier representations and agreements with the state[10], closed the Centralia mine in late 2006. From that time to the present, TransAlta has been shifting away from Centralia coal to PRB coal. TransAlta's own website noted that the shift was complete at the end of 2007.[11] Any reduction in NOx emissions is entirely incidental to a project that has been proposed for non-NOx reduction reasons. Therefore, as noted in Dr. Sahu's report, the Agreement attempts to satisfy BART requirements with the Flex Fuels project, yet with no

[8] Visibility and BART requirements have also been incorporated into Washington and SWCAA regulations. See e.g. WAC 173-400-030, 173-400-151, SWCAA 400-030, 400-151.

[9] See e.g. information from Ecology in response to questions by the Conservation Organizations (hereafter "Ecology Answers"), that in September 2007, TransAlta was already referring to the Boiler Efficiency Project. TransAlta later renamed the project "Flex Fuels" in January 2008 BART submissions. http://www.ecy.wa.gov/programs/air/TransAlta/Earthjustice.pdf..

[10] Including agreements that TransAlta would, in exchange for generous tax treatment from the state, keep the mine operating and the jobs associated with it. TransAlta has continued to receive the tax benefits, even after the mine closure.

[11] See also Ecology Answers.

additional incremental effort at NOx reduction by TransAlta beyond what it would be doing anyway.

2. There is no support in the record for the claimed NOx reduction from the Flex Fuels boiler efficiency project.

Even if Flex Fuels were appropriately in the running as a BART technology intended to address NOx and haze pollution in Class I areas, Ecology has not properly analyzed the Flex Fuels project and cannot rely on the claimed 20% NOx reduction. As set forth in Dr. Sahu's report, there are no technical details regarding combustion modeling in Ecology's record and therefore no way for the public to determine the appropriateness of the assumptions made, or the overall usefulness or accuracy of the analysis by either TransAlta or Ecology regarding the NOx reductions that may occur as an incidental benefit of the Flex Fuels boiler efficiency project. It appears that the information was not requested by, or provided to, Ecology.[12] Therefore, it also appears that Ecology did not actually analyze NOx reductions from the Flex Fuel project. Instead, Ecology has relied on a bare assertion by TransAlta. There is no way for Ecology or the public to determine whether a 20% incidental benefit is realistic or even meaningful. Flex Fuels cannot be considered as BART, because Ecology has failed to actually engage in at least steps 3 and 4 of the analysis and as a result, cannot have properly engaged in step 5. See 40 C.F.R. § 51.301.

3. Even after the application of Flex Fuels, the TransAlta coal plant will cause visibility impairments in twelve Class I areas.

Even after implementation of the Flex Fuels boiler efficiency project, the TransAlta coal plant will continue to cause significant visibility impairments at Mt. Rainier and Olympic National Parks as well as other Class I areas in the region and the Columbia River Gorge. As noted above, the TransAlta coal plant's NOx pollution impairs visibility in 12 Class I areas, including Mt. Rainier and Olympic National Parks. Even after application of the Flex Fuels project, the cumulative negative impact is 33 deciviews.[13] EPA considers a 1 deciview impact to be a cause of an impairment (and anything over .5 deciviews to be a contribution to impairment.) The TransAlta coal plant's impact on Mt. Rainier National Park alone will be 5 deciviews even after implementation of the boiler efficiency project—five times the level EPA considers a cause of a negative impact.[14] This indicates that even if Ecology were considering the boiler efficiency project as BART, Ecology has failed to adequately apply Step 5 of the BART analysis regarding improvements to visibility. See 40 C.F.R. § 51.301.

[12] Sahu Report at paragraph 5.

[13] A deciview is a measure of visibility impairment.

[14] See generally enclosed information and extinction graphs from NPS.

C. Selective Catalytic Reduction Technology Is BART.

The CAA, EPA regulations and guidance, state law, and the record all support Selective Catalytic Reduction technology ("SCR") as BART. As pointed out by Dr. Sahu, rejection of SCR is a "major error" in TransAlta and Ecology's determination of BART for the TransAlta coal plant.

1. SCR is technically feasible.

SCR is technically feasible, despite Ecology's unsupported statement to the contrary. Dr. Sahu notes that while Ecology makes a bald statement that SCR is technically infeasible, such a claim is not actually made in TransAlta's analysis or Ecology's own summary.[15] The only impediment listed is the "lack of room" (i.e. physical space limitations), for easy SCR installation. This does not mean that SCR cannot be installed, but only that it could potentially be costly. Therefore, under the 5-step BART analysis, SCR is technically feasible.

2. There is no support in the record for the claims regarding physical space limitations.

Even if the physical space limitation were to be considered a technical as opposed to cost issue, the record contains no evidence to support TransAlta's assertion. Dr. Sahu notes there is little to no engineering detail regarding the congestion.[16] While Ecology asked questions on this issue early in the process, TransAlta failed to provide information adequate to the task and Ecology apparently never followed up.[17] The figures that TransAlta did provide are barely legible and do not contain the level of engineering detail requested by Ecology or that is necessary to assess the claimed space limitations.[18] The figures provide no support for the claim of physical limitation for SCR and according to Dr. Sahu "certainly do not make the case for an engineering assessment of the degree of difficulty of the [SCR] retrofit."[19] Finally, the information from TransAlta is incomplete in that it contains no discussion of the potential for moving or re-configuring existing equipment, or how that factors into the physical limitation and cost discussions. For example, TransAlta fails to provide any information regarding moving or replacing the electro-static precipitators ("ESPs") or reconfiguring piping runs that would render

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[15] In fact, it appears that Ecology has been imprecise in its language regarding BART and SCR. It appears that Ecology believes that SCR would be technologically feasible at the TransAlta coal plant, but accepts TransAlta's rejection of it based upon cost reasons. See also Ecology's answers to Conservation Organizations' questions that the cost of SCR is "extreme" yet providing no support or detail regarding the claimed cost.

[16] Sahu Report, paragraph 6.

[17] Id.

[18] Id.

[19] Id.

an SCR retrofit less problematic.[20] Therefore, even if cost due to space limitations is properly considered a technical issue for installation of SCR, the analysis and information provided is inadequate to actually assess the problem.

3. The record has no explanation for TransAlta's failure to control the unusually high boiler-out NOx emissions at the TransAlta coal plant, a fundamental component of considering feasible BART technologies.

TransAlta and Ecology have failed to analyze all potential, technically feasible, control technologies because TransAlta and Ecology have not adequately assessed the situation with NOx emissions from the boilers themselves and possible improvements at the boilers. The current boiler-out NOx emissions are approximately 0.3 lb/MMBtu. The emissions are predicted to drop to 0.24 lb/MMBtu with the Flex Fuels project. Dr. Sahu finds that these emissions are very high given operations elsewhere in the industry. Numerous existing PRB-fired boilers are operating with NOx emissions much lower than those reported by the TransAlta coal plant, generally well below 0.15 lb/MMBtu.[21] None of the scientific and engineering literature that is widely-available on the subject nor any of the boiler emissions information available from the EPA database was discussed, compared, or analyzed relative to the BART analysis for the TransAlta coal plant. While Ecology appears to have inquired into why TransAlta's boiler NOx emissions are so high, according to Ecology TransAlta had no technical response.[22] The is no reason that TransAlta's boiler-out NOx emissions should be as high as 0.24 lb/MMBtu when using the claimed controls for the boilers along with PRB coals. Given known information from the industry and the literature, the NOx emissions should be closer to 0.10 lb/MMBtu for a well-run, baseload unit.[23]

The issue with the boiler emissions is fundamental to Ecology's BART analysis and determination. Minimizing boiler-out NOx will require less NOx control from add-on technologies such as SCR. For example, if NOx emissions from the boiler were kept within the industry levels outlined in Dr. Sahu's report, SCR technology could be smaller in size, reducing or obviating physical constraint concerns at the plant. The attendant improvements in visibility in the national parks and wilderness areas of such a combined approach would be huge.[24] TransAlta and Ecology have failed to assess this crucial connection between improved boiler-out

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[20] Id. It should also be noted that the NPS believes there are benefits for both NOx and mercury reductions with the removal of one or both ESPs and the use of baghouses for mercury control. Removal of the ESPs then makes room for the SCR. See King testimony and enclosed email from Bruce Polkowsky, NPS.

[21] See, paragraphs 7-9, Sahu Report and Table 1-6 therein.

[22] See also Ecology Answers where Ecology said it does not know why the boilers and Lo-NOx burners do not meet the level of performance usually attained by this technology.

[23] Sahu report, paragraph 10.

[24] Sahu Report, paragraph 11.

NOx emissions and appropriately-sized SCR. As a result, Ecology has failed to properly complete Steps 1 through 3 of the BART analysis.

4. There is no support in the record for TransAlta's high cost claims for the SCR technology.

Ecology has also not examined TransAlta's arguments regarding cost of SCR technology. The cost assumptions submitted by TransAlta do not appear tied to the claimed physical difficulties as there is no supporting documentation for the size of the SCR (which can vary), the physical limitations at the plant, or how either of those things specifically affect the cost of the retrofit. For example, there is no information regarding cost estimates other than costs ascribed to "vendor". The "vendor" identification is not even disclosed. Further, it is unclear what the vendors might have had at their disposal when the "vendor" rendered the opinion; it is conceivable that the vendor was simply offering something rough and off the cuff.[25] There are also items such as a "surcharge" of 16% with no explanation of what that is or what it's for or why 16% is the proper amount. Or, there is the straight doubling of the cost estimate from one SCR unit to two. As pointed out by Dr. Sahu, that makes no sense on its face as two SCRs would share several components.[26] Overall, the cost assertions are entirely unsupported and opaque. Unfortunately, Ecology appears to have nonetheless accepted them wholesale.

If Ecology is going to reject SCR as BART because it costs "too much", TransAlta and Ecology must produce much more information regarding those costs and consider costs as one step within the context of the five-step BART process. On the current record, there is no support for the rejection of SCR based on "cost".

D. Step 5 Of The Required BART Analysis Appears Almost Entirely Absent From Ecology's Process.

While it is unclear under which step Ecology is actually rejecting SCR, it if is Step 5 of the BART process and based on a claim that the improvement in visibility is not "worth" the cost, far more information and analysis is required before that conclusion can be drawn. Step 5 requires an assessment of the visibility improvement from technically-feasible control technologies. Ecology has given no indication of how it has addressed Step 5 in the BART analysis and it appears that it has not adequately assessed TransAlta's characterization of visibility improvements from SCR. As part of that, Ecology may weigh cost against improvement, but it must document how and why it reaches a particular decision.

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[25] See Sahu Report, paragraph 12. It is also unclear whether and to what extent TransAlta or Ecology used the Control Cost Manual recommended by the EPA BART guidelines in analyzing the cost of SCR at the TransAlta coal plant. EPA recommends use of the Manual in order that cost estimates are transparent and consistent across the nation. The NPS also recommends use of the Manual.

[26] Id.

1. Ecology did not question TransAlta's calculations that dilute the visibility improvement expected from SCR.

TransAlta's assessment of visibility improvement is unsupported and appears to be too small by virtue of two mistakes (or at least questions) in their calculation. First, Dr. Sahu notes an unexplained change in the baseline for calculation of cost-effectiveness of SCR NOx controls. Initially, TransAlta and Ecology were using a 2006-2007 baseline for emissions in order to calculate improvements in NOx emissions and the attendant improvement in visibility in Class I areas. However, later in the process, with the unsupported explanation that the period was "not representative" or "lower than average," TransAlta unilaterally and apparently arbitrarily selected 0.30 lb/MMBtu as the baseline. Ecology provides no discussion regarding the shift in baseline in the proposed Agreement or supporting documents. There is nothing in the record to support the assertions that 2006-2007 was somehow out of the ordinary or otherwise not appropriate for use as the baseline.[27] The shift had the potential effect of making SCR controls look less promising for visibility improvement.

The National Park Service has also identified a way in which TransAlta's accounting of visibility improvement underestimates the potential gains for the Class I areas. TransAlta's assessment focuses solely on improvement in Mt. Rainier National Park. While Mt. Rainier is the most-impacted of the many Class I areas the TransAlta coal plant affects, it is not the only one. TransAlta must take into account its cumulative negative impacts on a large number of Class I areas, all of which must attain and maintain pristine air quality. The cumulative improvement to the many Class I areas negatively affected by TransAlta's coal plant, is significantly larger, improving the cost-effectiveness of the SCR technology option. Again, there is no indication in the record or Ecology's decision document or the Agreement itself that Ecology recognized these issues, assessed them, or what Ecology might have decided about them. Ecology has failed to properly apply Step 5 of the BART analysis.

2. The record is devoid of evidence describing how Ecology balanced cost and visibility improvement, or any support indicating that Ecology necessarily struck the correct balance.

Ecology has provided no explanation of how it balanced the factors in its cost-effectiveness determination. As noted above, Ecology accepted TransAlta's cost figures at face value with no support. Then, Ecology accepted TransAlta's visibility improvement estimates at face value without inquiring into the dilution of the numbers from a changed baselines and/or failure to count all Class I areas. Even accepting these figures, Ecology fails in Step 5 because Ecology does not explain where it strikes the balance between costs and visibility improvement and why. If, in fact, Ecology has disregarded or failed to give sufficient weight to visibility improvements from SCR technology, Ecology has failed to properly apply Step 5 in the BART process. Ecology, in accepting TransAlta's approach, failed to explain its reason for finding that

[27] Sahu Report, paragraph 13.

approach reasonable and consistent with its CAA BART obligations.

The rejection of SCR technology and the apparently unquestioning acceptance of the cost effectiveness argument demonstrates a house of cards in Ecology's decision-making for the TransAlta coal plant. Ecology's decision regarding NOx controls is built upon unsupported assumptions resting on more unsupported assumptions. Even the simplest, most apparent questions do not appear to have been asked or answered. Therefore, the claimed BART determinations set forth in the Agreement are unfinished, unsupported, and inadequate. The Conservation Organizations object to the Agreement and strongly urge Ecology to reexamine the decision based upon the matters raised herein.

II. THE TRANSALTA COAL PLANT IS SUBJECT TO BART FOR NOX EMISSIONS.

Conservation Organizations disagree with Ecology's rationale for entering into an agreement that provides less protection for the State of Washington and the region's Class I areas than is required by federal law. TransAlta's expectation that it is not subject to BART is contrived and contrary to fact. Simple examination of the documents from the negotiations in the late 1990s demonstrates the flaws in TransAlta's position.[28]

First, the February 1998 order issued by SWCAA's predecessor agency is a RACT order, not BART. It says it is a RACT order on its face and each aspect of it provides that SWCAA is setting RACT for various pollutants at the TransAlta coal plant.

Second, also clear on the face of the RACT order, is the fact that the parties to the negotiation did not go through the BART process and did not meet all BART requirements for public process, consultations, and BART determinations. In fact the order itself pointedly states the parties' intentions to avoid the BART process by entering into the agreement and that the process was much more streamlined than a BART process would have been. Therefore, in keeping with its (or its predecessor's) own desired outcome at the time, TransAlta has not been subject to BART.[29]

Third, in approving the RACT order, EPA clearly and unequivocally found that the RACT order was not BART for NOx and that TransAlta would be subject to BART for NOx at

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[28] The Conservation Organizations understand that TransAlta argues it is not subject to BART because it and its immediate predecessor participated in a collaborative process in the late 1990s that resulted in changes to the plant. The Conservation Organizations also understand that TransAlta has set forth its arguments in a "White Paper" dated June 2007. While most of the negotiations on that earlier agreement (if not all) were done by TransAlta's predecessor, it appears that TransAlta is the owner that made the changes to the plant that were required by the negotiated agreement and the resulting RACT order.

[29] It actually appears that TransAlta has not been subject to BART for any of the pollutants at issue in the late 1990s, including sulfur dioxide and particulates. Nonetheless, Conservation Organizations' arguments here will remain focused on NOx.

some point in the future.

Fourth, the NPS was an important and active participant in the negotiations that led up to SWCAA's RACT order for the TransAlta coal plant. It is plain from its submissions in this process, that the NPS did not consider the agreements and the resulting RACT order to constitute a BART process and that the TransAlta plant had not been subject to BART, at least as to NOx pollutants.

TransAlta cannot, based upon these statements and the content of the order, believe that it is not subject to BART for NOx.

III. ECOLOGY SHOULD RETAIN ITS AUTHORITY TO REQUIRE FURTHER NOX REDUCTIONS REGARDLESS OF TRANSALTA'S ARGUMENTS.

Finally, regardless of whether TransAlta is subject to BART, the State, as recognized by Ecology, has the continuing authority and obligation to make reasonable further progress on improving visibility in Class I areas. See e.g. 42 U.S.C. § 7491(b). With TransAlta being the largest source of emissions and cumulative effects in the region, Ecology can and should impose additional controls in order to ensure reasonable further progress by 2018—something that clearly will not happen under the Agreement proposed.

And yet even here, Ecology ties its own hands. The Agreement provides that Ecology will affirmatively waive its reasonable further progress authority, in TransAlta's favor, until 2018.[30] And even then, Ecology has agreed that it will not impose additional controls on TransAlta if, between now and 2018, SWCAA imposes some very minimal additional NOx standards on the coal plant. Those additional NOx standards are truly minimal—they are less than presumptive BART and less than what other plants are achieving with better boiler-out performance as discussed by Dr. Sahu. Ecology fails to use any of the tools at its disposal to address this second largest negative impact on Class I areas in the nation. As a result, the Agreement should be rejected as contrary to the CAA and contrary to the public interest.

IV. THE MERCURY PORTIONS OF THE PROPOSED AGREEMENT AND CONSENT DECREE ARE INADEQUATE AND NOT IN THE PUBLIC INTEREST.

A. The TransAlta Coal Plant Is Washington's Largest Source of Toxic Mercury Emissions.

Reports for 2007 at the TransAlta coal plant show a combined mercury emission (just for the coal-fired units) of a little over 372 pounds for the year, making it the largest emitter of mercury in the state.[31] Mercury is a toxic pollutant which, when released into the atmosphere from coal plants and other sources, deposits into lakes, rivers, streams and the ocean where it

[30] Agreement at III (A)(2).

[31] Mercury Summary for 2007 and Air emissions Inventory for 2007, emissions units 1 and 2. Documents from SWCAA file for TransAlta Centralia Generation, L.L.C Centralia coal plant.

bioaccumulates in fish.[32] Ingestion of fish by humans leads to a variety of health problems, particularly for fetuses or children (whose nervous systems are still developing, making them particularly vulnerable to neurotoxins like mercury).[33] Nationwide, approximately 6-8% of women of childbearing age are at risk of having mercury blood levels that exceed levels associated with a variety of health risks and as a result, hundreds of children are born each year at risk of mercury-caused learning disabilities and other developmental problems.[34]

Recently, the NPS reported that Olympic and Mt. Rainier National Parks show high levels of mercury contamination in snow and in fish in mountain lakes. Some fish sampled exceeded health thresholds for human consumption while all fish from both parks exceeded health thresholds for one or more species of fish-eating wildlife.[35]

Ecology has claimed in public meetings and in their answers to Conservation Organizations' questions, that most of TransAlta's mercury enters the atmosphere, circles the world, and deposits over a large area.[36] Although Ecology summarily claims there is little local deposition, recent studies have shown that some types of mercury can deposit locally.[37] Ecology has not provided adequate analysis in the settlement agreement or supporting documentation that demonstrates that TransAlta mercury emissions do not have a local effect. It takes only a gram

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[32] See generally EPA information regarding mercury, e.g. http://publicaccess.custhelp.com/cgi-bin/publicaccess.cfg/php/enduser/std_adp.php?p_faqid=1824&p_created=1106159090&p_sid=zTcbbuLj&p_accessibility=0&p_redirect=&p_lva=&p_sp=cF9zcmNoPTEmcF9zb3J0X2J5PSZwX2dyaWRzb3J0PSZwX3Jvd19jbnQ9OSw5JnBfcHJvZHM9MjMzJnBfY2F0cz0mcF9wdj0xLjIzMyZwX2N2PSZwX3BhZ2U9MQ**&p_li=&p_topview=1 and http://www.epa.gov/mercury/advisories.htm

[33] Id.

[34] Report to Congress; U.S. Centers for Disease Control, Blood Mercury Levels in Young Children and Childbearing-Aged Women – United States, 1999-2002 (Nov. 5, 2004); Trasande, L., Landrigan, P.J., and Schechter, C., *Public Health and Economic Consequences of Methyl Mercury Toxicity to the Developing Brain.* Environmental Health Perspectives, 113(5), 590-596 (May 2005). See also http://www.epa.gov/ttn/atw/hlthef/mercury.html.

[35] http://www.nps.gov/olym/parknews/airborne-contaminants-study-released.htm. Western Airborne Contaminant Project, Feb. 2008.

[36] As noted by testifiers at the public meeting on October 13, 2009, the fact that a potent neurotoxin will likely affect other countries and their citizens rather than Washington's citizens is a poor reason to decline to strongly regulate the toxin.

[37] See Gerald J. Keeler, M.S. Landis, G.A. Norris, E.M. Christianson, and J.T. Dvonch, "Sources of Mercury Wet Deposition in Eastern Ohio, USA," Environmental Science and Technology (American Chemical Society), Vol. 40 (19), 5874-5881 (2006); Watkins, et al., EPA National Exposure Research Laboratory, Preliminary Results From Steubenville Hg Deposition Source Apportionment Study (April 27, 2005).

of mercury to contaminate a 20 acre lake such that the fish in that lake exceed the consumption standard for human health.[38] Clearly, if even a very small fraction of TransAlta's mercury is being deposited locally, Lewis County's and Washington's citizens are being greatly affected.

B. Contrary To Assertions In The Proposed Agreement, The State Has The Authority And The Obligation To Control Mercury Emissions From the TransAlta Coal Plant.

Ecology incorrectly asserts that it cannot regulate mercury from the TransAlta coal plant because it abandoned its rulemaking effort over a year ago when the federal Clean Air Mercury Rule was overturned by the U.S. Circuit Court of Appeals for the D.C. Circuit.[39] It further claims that now it must sit and wait for EPA to complete a MACT standard for mercury from power plants before Ecology can take any action to limit the large amount of this toxic pollutant from the TransAlta coal plant. Ecology's position on this issue is simply not supported by Washington or federal law.

WAC 173-400-040(5) provides that:

> No person shall cause or permit the emission of any air contaminant from any "source" if it is detrimental to the health, safety, or welfare of any person, or causes damage to property or business.

An air contaminant is defined to include vapor and gas, and air pollution is the presence of one or more air contaminants in such quantities or characteristics as to be or likely to be injurious to human health, plant, or animal life, or property or that unreasonably interferes with the enjoyment thereof. RCW 70.94.030; WAC 173-400-030. Washington law also requires that all emissions units be required to use RACT to control emissions. WAC 173-400-040. Clearly, Ecology has both the authority and the obligation under Washington law to regulate mercury from the TransAlta coal plant.

Moreover, there is no need for Ecology to engage in formal rulemaking in order to address TransAlta's mercury. Washington law provides that for categories where there are fewer than three sources (the case here as the TransAlta coal plant is Washington's only coal-fired power plant), Ecology may proceed to determine and apply RACT on a case by case basis, without rulemaking. RCW 70.94.154. RCW 70.94.154 further provides that Ecology may make a source-specific RACT determination where such a determination is needed to address specific air quality problems for which the source is a significant contributor. As noted above, TransAlta's coal plant is the single largest source of toxic mercury in the state.

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[38] http://www.newmoa.org/prevention/mercury/mercurylake.pdf and http://yosemite.epa.gov/opa/admpress.nsf/d0cf6618525a9efb85257359003fb69d/88c64f9ee84a23e4852574240004276d!OpenDocument

[39] See Agreement at II(17) (citing New Jersey v. EPA, 517 F.3d 574 (D.C. Cir. 2008)).

Nor is there a need to wait for the EPA to regulate mercury before the state takes action to regulate this toxic pollutant. The Clean Air Act clearly provides that states can always regulate air pollutants more stringently than the Clean Air Act and/or federal regulation. 42 U.S.C. § 7416; Exxon Mobil Corp. v. EPA, 217 F.3d 1246, 1255 (9th Cir. 2000) ("Air pollution prevention falls under the broad police powers of the states, which include the power to protect the health of citizens in the state."). In fact, many states are already leading the way and requiring significant mercury reductions, regardless of the status of rules from EPA.[40]

Ecology cannot argue a lack of authority as a reason for entering into this token Agreement regarding mercury.

C. The Industry Is Currently Achieving 90% And Better Reductions In Mercury Emissions, A Standard To Which TransAlta Should Be Held.

The voluntary 50% reductions in mercury emissions from the TransAlta coal plant fall far short of what is being achieved in the industry. Greater than 90% mercury removal has been achieved on a long-term basis at a number of PRB-coal-fired power plants using activated carbon technology.[41] The Government Accountability Office recently made similar findings: that activated carbon technology is allowing a number of coal-fired power plants to remove over 90% of the mercury in their emissions and to do so at a fairly low cost.[42] Finally, Ecology's own files on this matter contain scientific and engineering papers about 80%, 90% and even better mercury reduction at various power plants.[43]

Activated carbon injection technology is the very technology currently being tested at the TransAlta coal plant. Clearly, Ecology should receive more than TransAlta's minimal efforts on this toxic pollutant. It appears TransAlta could achieve much better than the 50% offered in the Agreement and it could do better with fairly minimal additional cost.

Finally, the NPS raised an interesting point, supported by the GAO Report, in Acting

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[40] See Appendix III, U.S. Government Accountability Office, "Mercury Control Technologies at Coal-Fired Power Plants Have Achieved Substantial Emissions Reductions," GAO-10-47 (October 2009) ("GAO Report").

[41] See examples discussed in Sahu Report, paragraphs 23-25.

[42] GAO Report generally.

[43] See e.g. R. Chang, et al., Development and Demonstration of Mercury Control by Dry Technologies: 2005 Update, EPRI Document # 1004263 (Feb. 2005). See also March 30, 2009 Letter from the Institute of Clean Air companies to Director Jay Manning, Ecology, regarding mercury removal technologies and Seeliger, J., Brown, J.H., Jankura, B., Redinger, K., "Cost Effective Mercury Emissions Control At the Newmont TS Power Plant" (2008) (presented at Power Plant Air Pollutant Control "Mega" Symposium, August 2008).

Superintendent King's testimony at the public meeting on October 13, 2009. Superintendent King noted that if the TransAlta coal plant were to install BART—SCR technology—for the control of NOx, the plant would also obtain increased mercury reduction benefits. This finding is echoed by the GAO Report that notes that plants that have installed technologies for the control of other pollutants, such as NOx, have found significant co-benefits for the control of mercury.[44]

Given the state of mercury control technology and the clear authority of the state to regulate mercury, the voluntary 50% mercury reduction at the TransAlta coal plant is far too minimal, not in compliance with Washington's Clean Air Act requirements, and contrary to the public interest.

V. THE PROPOSED AGREEMENT AND CONSENT DECREE INCLUDE VARIOUS CLAUSES AND CONSTRAINTS THAT FURTHER WEAKEN THE AGREEMENT.

In addition to the very weak standards for NOx and mercury control in the Agreement, the Agreement contains a number of other constraints on TransAlta's obligations, constraints on Ecology's enforcement of the Agreement terms, and vaguely-stated additional commitments by Ecology. These additional terms further demonstrate that the Agreement is weak and not in the public interest.

First, as noted above, the commitments by TransAlta regarding mercury are wholly voluntary. Therefore, TransAlta could, for a variety of reasons, choose to do nothing with respect to mercury reduction.[45] The Agreement's terms are clear that in that instance, Ecology cannot enforce even the 50% obligation. The Agreement also provides that, at its sole option, TransAlta could simply choose to spend up to a certain amount on mercury-related tasks, but no more, regardless of whether the 50% reductions are achieved. Further, if TransAlta and Ecology wished to reach a meaningful and enforceable agreement to reduce mercury emissions, they could use the legal mechanism that currently exists under Washington law: WAC 173-400-091 ("Voluntary limits on emissions"). That provision would allow Ecology to issue a regulatory order setting the mercury emission limit at the agreed-to level, and, after appropriate notice and comment, establish a federally-enforceable mercury limit. WAC 173-401-091(4)-(5). Therefore, even the 50% reduction, meager though it is, is in question.

As to NOx, in addition to requiring no additional NOx reduction beyond what the TransAlta coal plant already chooses to do, Ecology agrees to forego any further progress on

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[44] GAO Report, pp. 5-6.

[45] Ecology claims that it could, if TransAlta failed to follow-through on its voluntary commitments, engage in mercury rulemaking to compel mercury reductions. This is curious given Ecology's stated reasons for entering into the Agreement in the first instance. If Ecology has the authority do so, Ecology should exercise that authority to the benefit of the public and the environment and not settle for such a paltry result as represented by TransAlta's commitments in the Agreement. It is unclear at this juncture, just what Ecology believes its authority really is.

NOx reductions from the plant for almost ten years (and possibly longer). Again, Ecology relinquished authority that it could retain in order to ensure that, should the Class I areas remain significantly impaired by the TransAlta coal plant's pollution even after the agreed NOx reductions, it could impose additional reductions to obtain reasonable further progress on the impairment problem. In fact, the Agreement goes a step further in making commitments to TransAlta. Ecology agrees that it will not even require additional reductions in 2018, regardless of the status of the Class I areas, if SWCAA imposes a slightly lower NOx requirement on the TransAlta coal plant than that which is required in the Agreement. Again, the slightly lower NOx requirement would still not achieve the presumptive BART limit of 0.15 lb/MMBtu and would be well above even the boiler-out control of NOx that many PRB-fired plants currently achieve.

The Conservation Organizations further oppose the language of paragraph 11 of the Agreement regarding coal ash waste disposal. Ecology agrees to "support" any future proposal and measures by TransAlta to reduce the cost of dealing with its ash waste or other byproducts that have been contaminated with mercury (or other heavy metals that precipitate out into the ash as a result of pollutant controls.) The Agreement notes that such "support" may include approval of "beneficial uses". Beneficial uses is not defined. Again, this appears to be a provision where Ecology relinquishes regulatory authority for nothing in return. This is particularly troubling in light of recent coal ash disasters such as the TVA coal plant spill in December of 2008, or problems with groundwater contamination in communities that have allowed "beneficial uses" of coal ash in roads and as fill for recreational developments. This kind of advance approval of any and all coal ash projects that might "reduce costs" or be considered "beneficial" by TransAlta is per se arbitrary and capricious decision-making by Ecology. Inadequately disposed coal ash waste may lead to detrimental public health and ecological consequences. It is entirely inappropriate for Ecology to pledge and agree to support proposals without even knowing what those proposals are.

CONCLUSION

It is extremely unfortunate and puzzling why Ecology feels compelled to reach this lopsided Agreement with TransAlta. This Agreement is not a compromise as between two ends of a spectrum, but rather a capitulation. Ecology and the citizens of Washington get nothing from this "bargain" that TransAlta wasn't already going to give them. TransAlta gets exactly everything it wants: it is not subject to BART for NOx; it is not required to do anything to control NOx pollution that is it not already doing and would do regardless of this Agreement; it can do minimal mercury control, well below industry standards, at its sole option with no repercussions if it does not achieve the reductions agreed to. In return, Ecology agrees to "hands-off" treatment for the next ten years or more for the TransAlta coal plant on a number of pollution issues; the state agrees to become TransAlta's partner in seeking accommodation and/or positive treatment from the EPA on a number of pollution issues; and the state agrees to look kindly on a wide-ranging list of potential TransAlta proposals for dealing with coal ash waste. Conservation Organizations find that the Agreement provides nothing of benefit for the citizens and natural resources of this state and strongly urge the State to reject this Agreement and engage in a full-scale, thorough BART analysis for NOx and aggressive case by case

mercury control in line with industry achievements of over 90% reductions.

Sincerely,

Janette K. Brimmer
Earthjustice
Counsel for National Parks Conservation Association, the Sierra Club, and Northwest Environmental Defense Center

cc: Doug Howell, SC
Mark Riskedahl, NEDC
Stephanie Kodish and Sean Smith NPCA
Don Shepherd, NPS
Region 10 EPA

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-118:
Energy Transition Bill, SB 5769

CERTIFICATION OF ENROLLMENT

ENGROSSED SECOND SUBSTITUTE SENATE BILL 5769

Chapter 180, Laws of 2011

62nd Legislature
2011 Regular Session

COAL-FIRED ELECTRIC GENERATION FACILITIES

EFFECTIVE DATE: 07/22/11

Passed by the Senate April 21, 2011
YEAS 33 NAYS 14

BRAD OWEN

President of the Senate

Passed by the House April 11, 2011
YEAS 87 NAYS 9

FRANK CHOPP

Speaker of the House of Representatives

Approved April 29, 2011, 10:59 a.m.

CHRISTINE GREGOIRE

Governor of the State of Washington

CERTIFICATE

I, Thomas Hoemann, Secretary of the Senate of the State of Washington, do hereby certify that the attached is **ENGROSSED SECOND SUBSTITUTE SENATE BILL 5769** as passed by the Senate and the House of Representatives on the dates hereon set forth.

THOMAS HOEMANN

Secretary

FILED

April 29, 2011

Secretary of State
State of Washington

ENGROSSED SECOND SUBSTITUTE SENATE BILL 5769

AS AMENDED BY THE HOUSE

Passed Legislature - 2011 Regular Session

State of Washington 62nd Legislature 2011 Regular Session

By Senate Ways & Means (originally sponsored by Senators Rockefeller, Pridemore, Kohl-Welles, White, Chase, Murray, Ranker, Regala, Fraser, Shin, and Kline)

READ FIRST TIME 02/25/11.

AN ACT Relating to coal-fired electric generation facilities; amending RCW 80.80.040, 80.80.070, 80.50.100, 43.160.076, and 19.280.030; reenacting and amending RCW 80.80.010 and 80.80.060; adding new sections to chapter 80.80 RCW; adding a new section to chapter 43.155 RCW; adding new sections to chapter 80.04 RCW; adding a new section to chapter 80.70 RCW; adding a new chapter to Title 80 RCW; creating a new section; providing an expiration date; and providing a contingent expiration date.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF WASHINGTON:

NEW SECTION. **Sec. 101.** (1) The legislature finds that generating electricity from the combustion of coal produces pollutants that are harmful to human health and safety and the environment. While the emission of many of these pollutants continues to be addressed through application of federal and state air quality laws, the emission of greenhouse gases resulting from the combustion of coal has not been addressed.

(2) The legislature finds that coal-fired electricity generation is one of the largest sources of greenhouse gas emissions in the state,

and is the largest source of such emissions from the generation of electricity in the state.

(3) The legislature finds coal-fired electric generation may provide baseload power that is necessary in the near-term for the stability and reliability of the electrical transmission grid and that contributes to the availability of affordable power in the state. The legislature further finds that efforts to transition power to other fuels requires a reasonable period of time to ensure grid stability and to maintain affordable electricity resources.

(4) The legislature finds that coal-fired baseload electric generation facilities are a significant contributor to family-wage jobs and economic health in parts of the state and that transition of these facilities must address the economic future and the preservation of jobs in affected communities.

(5) Therefore, it is the purpose of this act to provide for the reduction of greenhouse gas emissions from large coal-fired baseload electric power generation facilities, to effect an orderly transition to cleaner fuels in a manner that ensures reliability of the state's electrical grid, to ensure appropriate cleanup and site restoration upon decommissioning of any of these facilities in the state, and to provide assistance to host communities planning for new economic development and mitigating the economic impacts of the closure of these facilities.

Sec. 102. RCW 80.80.010 and 2009 c 565 s 54 and 2009 c 448 s 1 are each reenacted and amended to read as follows:

The definitions in this section apply throughout this chapter unless the context clearly requires otherwise.

(1) "Attorney general" means the Washington state office of the attorney general.

(2) "Auditor" means: (a) The Washington state auditor's office or its designee for consumer-owned utilities under its jurisdiction; or (b) an independent auditor selected by a consumer-owned utility that is not under the jurisdiction of the state auditor.

(3) "Average available greenhouse gas emissions output" means the level of greenhouse gas emissions as surveyed and determined by the energy policy division of the department of commerce under RCW 80.80.050.

(4) "Baseload electric generation" means electric generation from a power plant that is designed and intended to provide electricity at an annualized plant capacity factor of at least sixty percent.

(5) "Cogeneration facility" means a power plant in which the heat or steam is also used for industrial or commercial heating or cooling purposes and that meets federal energy regulatory commission standards for qualifying facilities under the public utility regulatory policies act of 1978 (16 U.S.C. Sec. 824a-3), as amended.

(6) "Combined-cycle natural gas thermal electric generation facility" means a power plant that employs a combination of one or more gas turbines and steam turbines in which electricity is produced in the steam turbine from otherwise lost waste heat exiting from one or more of the gas turbines.

(7) "Commission" means the Washington utilities and transportation commission.

(8) "Consumer-owned utility" means a municipal utility formed under Title 35 RCW, a public utility district formed under Title 54 RCW, an irrigation district formed under chapter 87.03 RCW, a cooperative formed under chapter 23.86 RCW, a mutual corporation or association formed under chapter 24.06 RCW, or port district within which an industrial district has been established as authorized by Title 53 RCW, that is engaged in the business of distributing electricity to more than one retail electric customer in the state.

(9) "Department" means the department of ecology.

(10) "Distributed generation" means electric generation connected to the distribution level of the transmission and distribution grid, which is usually located at or near the intended place of use.

(11) "Electric utility" means an electrical company or a consumer-owned utility.

(12) "Electrical company" means a company owned by investors that meets the definition of RCW 80.04.010.

(13) "Governing board" means the board of directors or legislative authority of a consumer-owned utility.

(14) "Greenhouse ((~~gases~~)) gas" includes carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

(15) "Long-term financial commitment" means:

(a) Either a new ownership interest in baseload electric generation or an upgrade to a baseload electric generation facility; or

(b) A new or renewed contract for baseload electric generation with a term of five or more years for the provision of retail power or wholesale power to end-use customers in this state.

(16) "Plant capacity factor" means the ratio of the electricity produced during a given time period, measured in kilowatt-hours, to the electricity the unit could have produced if it had been operated at its rated capacity during that period, expressed in kilowatt-hours.

(17) "Power plant" means a facility for the generation of electricity that is permitted as a single plant by a jurisdiction inside or outside the state.

(18) "Upgrade" means any modification made for the primary purpose of increasing the electric generation capacity of a baseload electric generation facility. "Upgrade" does not include routine or necessary maintenance, installation of emission control equipment, installation, replacement, or modification of equipment that improves the heat rate of the facility, or installation, replacement, or modification of equipment for the primary purpose of maintaining reliable generation output capability that does not increase the heat input or fuel usage as specified in existing generation air quality permits as of July 22, 2007, but may result in incidental increases in generation capacity.

(19) "Coal transition power" means the output of a coal-fired electric generation facility that is subject to an obligation to meet the standards contained in RCW 80.80.040(3)(c).

(20) "Memorandum of agreement" or "memorandum" means a binding and enforceable contract entered into pursuant to section 106 of this act between the governor on behalf of the state and an owner of a baseload electric generation facility in the state that produces coal transition power.

Sec. 103. RCW 80.80.040 and 2009 c 448 s 2 are each amended to read as follows:

(1) Beginning July 1, 2008, the greenhouse gas emissions performance standard for all baseload electric generation for which electric utilities enter into long-term financial commitments on or after such date is the lower of:

(a) One thousand one hundred pounds of greenhouse gases per megawatt-hour; or

(b) The average available greenhouse gas emissions output as determined under RCW 80.80.050.

(2) This chapter does not apply to long-term financial commitments with the Bonneville power administration.

(3)(a) Except as provided in (c) of this subsection, all baseload electric generation facilities in operation as of June 30, 2008, are deemed to be in compliance with the greenhouse gas emissions performance standard established under this section until the facilities are the subject of long-term financial commitments.

(b) All baseload electric generation that commences operation after June 30, 2008, and is located in Washington, must comply with the greenhouse gas emissions performance standard established in subsection (1) of this section.

(c)(i) A coal-fired baseload electric generation facility in Washington that emitted more than one million tons of greenhouse gases in any calendar year prior to 2008 must comply with the lower of the following greenhouse gas emissions performance standard such that one generating boiler is in compliance by December 31, 2020, and any other generating boiler is in compliance by December 31, 2025:

(A) One thousand one hundred pounds of greenhouse gases per megawatt-hour; or

(B) The average available greenhouse gas emissions output as determined under RCW 80.80.050.

(ii) This subsection (3)(c) does not apply to a coal-fired baseload electric generating facility in the event the department determines as a requirement of state or federal law or regulation that selective catalytic reduction technology must be installed on any of its boilers.

(4) All electric generation facilities or power plants powered exclusively by renewable resources, as defined in RCW 19.280.020, are deemed to be in compliance with the greenhouse gas emissions performance standard established under this section.

(5) All cogeneration facilities in the state that are fueled by natural gas or waste gas or a combination of the two fuels, and that are in operation as of June 30, 2008, are deemed to be in compliance with the greenhouse gas emissions performance standard established

under this section until the facilities are the subject of a new ownership interest or are upgraded.

(6) In determining the rate of emissions of greenhouse gases for baseload electric generation, the total emissions associated with producing electricity shall be included.

(7) In no case shall a long-term financial commitment be determined to be in compliance with the greenhouse gas emissions performance standard if the commitment includes more than twelve percent of electricity from unspecified sources.

(8) For a long-term financial commitment with multiple power plants, each specified power plant must be treated individually for the purpose of determining the annualized plant capacity factor and net emissions, and each power plant must comply with subsection (1) of this section, except as provided in subsections (3) through (5) of this section.

(9) The department shall establish an output-based methodology to ensure that the calculation of emissions of greenhouse gases for a cogeneration facility recognizes the total usable energy output of the process, and includes all greenhouse gases emitted by the facility in the production of both electrical and thermal energy. In developing and implementing the greenhouse gas emissions performance standard, the department shall consider and act in a manner consistent with any rules adopted pursuant to the public utilities regulatory policy act of 1978 (16 U.S.C. Sec. 824a-3), as amended.

(10) The following greenhouse gas emissions produced by baseload electric generation owned or contracted through a long-term financial commitment shall not be counted as emissions of the power plant in determining compliance with the greenhouse gas emissions performance standard:

(a) Those emissions that are injected permanently in geological formations;

(b) Those emissions that are permanently sequestered by other means approved by the department; and

(c) Those emissions sequestered or mitigated as approved under subsection (16) of this section.

(11) In adopting and implementing the greenhouse gas emissions performance standard, the department of ((~~community, trade, and economic development~~)) commerce energy policy division, in consultation

with the commission, the department, the Bonneville power administration, the western electricity ((~~coordination [coordinating]~~)) coordinating council, the energy facility site evaluation council, electric utilities, public interest representatives, and consumer representatives, shall consider the effects of the greenhouse gas emissions performance standard on system reliability and overall costs to electricity customers.

(12) In developing and implementing the greenhouse gas emissions performance standard, the department shall, with assistance of the commission, the department of ((~~community, trade, and economic development~~)) commerce energy policy division, and electric utilities, and to the extent practicable, address long-term purchases of electricity from unspecified sources in a manner consistent with this chapter.

(13) The directors of the energy facility site evaluation council and the department shall each adopt rules under chapter 34.05 RCW in coordination with each other to implement and enforce the greenhouse gas emissions performance standard. The rules necessary to implement this section shall be adopted by June 30, 2008.

(14) In adopting the rules for implementing this section, the energy facility site evaluation council and the department shall include criteria to be applied in evaluating the carbon sequestration plan, for baseload electric generation that will rely on subsection (10) of this section to demonstrate compliance, but that will commence sequestration after the date that electricity is first produced. The rules shall include but not be limited to:

(a) Provisions for financial assurances, as a condition of plant operation, sufficient to ensure successful implementation of the carbon sequestration plan, including construction and operation of necessary equipment, and any other significant costs;

(b) Provisions for geological or other approved sequestration commencing within five years of plant operation, including full and sufficient technical documentation to support the planned sequestration;

(c) Provisions for monitoring the effectiveness of the implementation of the sequestration plan;

(d) Penalties for failure to achieve implementation of the plan on schedule;

(e) Provisions for an owner to purchase emissions reductions in the event of the failure of a sequestration plan under subsection (16) of this section; and

(f) Provisions for public notice and comment on the carbon sequestration plan.

(15)(a) Except as provided in (b) of this subsection, as part of its role enforcing the greenhouse gas emissions performance standard, the department shall determine whether sequestration or a plan for sequestration will provide safe, reliable, and permanent protection against the greenhouse gases entering the atmosphere from the power plant and all ancillary facilities.

(b) For facilities under its jurisdiction, the energy facility site evaluation council shall contract for review of sequestration or the carbon sequestration plan with the department consistent with the conditions under (a) of this subsection, consider the adequacy of sequestration or the plan in its adjudicative proceedings conducted under RCW 80.50.090(3), and incorporate specific findings regarding adequacy in its recommendation to the governor under RCW 80.50.100.

(16) A project under consideration by the energy facility site evaluation council by July 22, 2007, is required to include all of the requirements of subsection (14) of this section in its carbon sequestration plan submitted as part of the energy facility site evaluation council process. A project under consideration by the energy facility site evaluation council by July 22, 2007, that receives final site certification agreement approval under chapter 80.50 RCW shall make a good faith effort to implement the sequestration plan. If the project owner determines that implementation is not feasible, the project owner shall submit documentation of that determination to the energy facility site evaluation council. The documentation shall demonstrate the steps taken to implement the sequestration plan and evidence of the technological and economic barriers to successful implementation. The project owner shall then provide to the energy facility site evaluation council notification that they shall implement the plan that requires the project owner to meet the greenhouse gas emissions performance standard by purchasing verifiable greenhouse gas emissions reductions from an electric ((~~generating~~)) generation facility located within the western interconnection, where the reduction would not have occurred otherwise or absent this contractual

agreement, such that the sum of the emissions reductions purchased and the facility's emissions meets the standard for the life of the facility.

Sec. 104. RCW 80.80.060 and 2009 c 448 s 3 and 2009 c 147 s 1 are each reenacted and amended to read as follows:

(1) No electrical company may enter into a long-term financial commitment unless the baseload electric generation supplied under such a long-term financial commitment complies with the greenhouse ((~~gases [gas]~~)) gas emissions performance standard established under RCW 80.80.040.

(2) In order to enforce the requirements of this chapter, the commission shall review in a general rate case or as provided in subsection (5) of this section any long-term financial commitment entered into by an electrical company after June 30, 2008, to determine whether the baseload electric generation to be supplied under that long-term financial commitment complies with the greenhouse ((~~gases [gas]~~)) gas emissions performance standard established under RCW 80.80.040.

(3) In determining whether a long-term financial commitment is for baseload electric generation, the commission shall consider the design of the power plant and its intended use, based upon the electricity purchase contract, if any, permits necessary for the operation of the power plant, and any other matter the commission determines is relevant under the circumstances.

(4) Upon application by an electric utility, the commission may provide a case-by-case exemption from the greenhouse ((~~gases [gas]~~)) gas emissions performance standard to address: (a) Unanticipated electric system reliability needs; (b) extraordinary cost impacts on utility ratepayers; or (c) catastrophic events or threat of significant financial harm that may arise from unforeseen circumstances.

(5) Upon application by an electrical company, the commission shall determine whether the company's proposed decision to acquire electric generation or enter into a power purchase agreement for electricity complies with the greenhouse ((~~gases [gas]~~)) gas emissions performance standard established under RCW 80.80.040. The commission shall not decide in a proceeding under this subsection (5) issues involving the actual costs to construct and operate the selected resource, cost

recovery, or other issues reserved by the commission for decision in a general rate case or other proceeding for recovery of the resource or contract costs.

(6) An electrical company may account for and defer for later consideration by the commission costs incurred in connection with a long-term financial commitment, including operating and maintenance costs, depreciation, taxes, and cost of invested capital. The deferral begins with the date on which the power plant begins commercial operation or the effective date of the power purchase agreement and continues for a period not to exceed twenty-four months; provided that if during such period the company files a general rate case or other proceeding for the recovery of such costs, deferral ends on the effective date of the final decision by the commission in such proceeding. Creation of such a deferral account does not by itself determine the actual costs of the long-term financial commitment, whether recovery of any or all of these costs is appropriate, or other issues to be decided by the commission in a general rate case or other proceeding for recovery of these costs. For the purpose of this subsection (6) only, the term "long-term financial commitment" also includes an electric company's ownership or power purchase agreement with a term of five or more years associated with an eligible renewable resource as defined in RCW 19.285.030.

(7) The commission shall consult with the department to apply the procedures adopted by the department to verify the emissions of greenhouse gases from baseload electric generation under RCW 80.80.040. The department shall report to the commission whether baseload electric generation will comply with the greenhouse ((~~gases [gas]~~)) gas emissions performance standard for the duration of the period the baseload electric generation is supplied to the electrical company.

(8) The commission shall adopt rules for the enforcement of this section with respect to electrical companies and adopt procedural rules for approving costs incurred by an electrical company under subsection (4) of this section.

(9) This section does not apply to a long-term financial commitment for the purchase of coal transition power with termination dates consistent with the applicable dates in RCW 80.80.040(3)(c).

(10) The commission shall adopt rules necessary to implement this section by December 31, 2008.

Sec. 105. RCW 80.80.070 and 2007 c 307 s 9 are each amended to read as follows:

(1) No consumer-owned utility may enter into a long-term financial commitment unless the baseload electric generation supplied under such a long-term financial commitment complies with the greenhouse ((~~gases~~)) gas emissions performance standard established under RCW 80.80.040.

(2) The governing board shall review and make a determination on any long-term financial commitment by the utility, pursuant to this chapter and after consultation with the department, to determine whether the baseload electric generation to be supplied under that long-term financial commitment complies with the greenhouse ((~~gases~~)) gas emissions performance standard established under RCW 80.80.040. No consumer-owned utility may enter into a long-term financial commitment unless the baseload electric generation to be supplied under that long-term financial commitment complies with the greenhouse ((~~gases~~)) gas emissions performance standard established under RCW 80.80.040.

(3) In confirming that a long-term financial commitment is for baseload electric generation, the governing board shall consider the design of the power plant and the intended use of the power plant based upon the electricity purchase contract, if any, permits necessary for the operation of the power plant, and any other matter the governing board determines is relevant under the circumstances.

(4) The governing board may provide a case-by-case exemption from the greenhouse ((~~gases~~)) gas emissions performance standard to address: (a) Unanticipated electric system reliability needs; or (b) catastrophic events or threat of significant financial harm that may arise from unforeseen circumstances.

(5) The governing board shall apply the procedures adopted by the department to verify the emissions of greenhouse gases from baseload electric generation under RCW 80.80.040, and may request assistance from the department in doing so.

(6) For consumer-owned utilities, the auditor is responsible for auditing compliance with this chapter and rules adopted under this chapter that apply to those utilities and the attorney general is responsible for enforcing that compliance.

(7) This section does not apply to long-term financial commitments for the purchase of coal transition power with termination dates consistent with the applicable dates in RCW 80.80.040(3)(c).

NEW SECTION. **Sec. 106.** A new section is added to chapter 80.80 RCW to read as follows:

(1) By January 1, 2012, the governor on behalf of the state shall enter into a memorandum of agreement that takes effect on April 1, 2012, with the owners of a coal-fired baseload facility in Washington that emitted more than one million tons of greenhouse gases in any calendar year prior to 2008. The memorandum of agreement entered into by the governor may only contain provisions authorized in this section, except as provided under section 108 of this act.

(2) The memorandum of agreement must:

(a) Incorporate by reference RCW 80.80.040, 80.80.060, and 80.80.070 as of the effective date of this section;

(b) Incorporate binding commitments to install selective noncatalytic reduction pollution control technology in any coal-fired generating boilers by January 1, 2013, after discussing the proper use of ammonia in this technology.

(3)(a) The memorandum of agreement must include provisions by which the facility owner will provide financial assistance:

(i) To the affected community for economic development and energy efficiency and weatherization; and

(ii) For energy technologies with the potential to create considerable energy, economic development, and air quality, haze, or other environmental benefits.

(b) Except as described in (c) of this subsection, the financial assistance in (a)(i) of this subsection must be in the amount of thirty million dollars and the financial assistance in (a)(ii) of this subsection must be in the amount of twenty-five million dollars, with investments beginning January 1, 2012, and consisting of equal annual investments through December 31, 2023, or until the full amount has been provided. Only funds for energy efficiency and weatherization may be spent prior to December 31, 2015.

(c) If the tax exemptions provided under RCW 82.08.811 or 82.12.811 are repealed, any remaining financial assistance required by this section is no longer required.

(4) The memorandum of agreement must:

(a) Specify that the investments in subsection (3) of this section be held in independent accounts at an appropriate financial institution; and

(b) Identify individuals to approve expenditures from the accounts. Individuals must have relevant expertise and must include members representing the Lewis county economic development council, local elected officials, employees at the facility, and the facility owner.

(5) The memorandum of agreement must include a provision that allows for the termination of the memorandum of agreement in the event the department determines as a requirement of state or federal law or regulation that selective catalytic reduction technology must be installed on any of its boilers.

(6) The memorandum of agreement must include enforcement provisions to ensure implementation of the agreement by the parties.

(7) If the memorandum of agreement is not signed by January 1, 2012, the governor must impose requirements consistent with the provisions in subsection (2)(b) of this section.

NEW SECTION. **Sec. 107.** A new section is added to chapter 80.80 RCW to read as follows:

No state agency or political subdivision of the state may adopt or impose a greenhouse gas emission performance standard, or other operating or financial requirement or limitation relating to greenhouse gas emissions, on a coal-fired electric generation facility located in Washington in operation on or before the effective date of this section or upon an electric utility's long-term purchase of coal transition power, that is inconsistent with or in addition to the provisions of RCW 80.80.040 or the memorandum of agreement entered into under section 106 of this act.

NEW SECTION. **Sec. 108.** A new section is added to chapter 80.80 RCW to read as follows:

(1) A memorandum of agreement entered into pursuant to section 106 of this act may include provisions to assist in the financing of emissions reductions that exceed those required by RCW 80.80.040(3)(c) by providing for the recognition of such reductions in applicable state policies and programs relating to greenhouse gas emissions, and by encouraging and advocating for the recognition of the reductions in all established and emerging emission reduction frameworks at the regional, national, or international level.

(2) The governor may recommend actions to the legislature to strengthen implementation of an agreement or a proposed agreement relating to recognition of investments in emissions reductions described in subsection (1) of this section.

Sec. 109. RCW 80.50.100 and 1989 c 175 s 174 are each amended to read as follows:

(1)(a) The council shall report to the governor its recommendations as to the approval or rejection of an application for certification within twelve months of receipt by the council of such an application, or such later time as is mutually agreed by the council and the applicant.

(b) In the case of an application filed prior to December 31, 2025, for certification of an energy facility proposed for construction, modification, or expansion for the purpose of providing generating facilities that meet the requirements of RCW 80.80.040 and are located in a county with a coal-fired electric generating facility subject to RCW 80.80.040(3)(c), the council shall expedite the processing of the application pursuant to RCW 80.50.075 and shall report its recommendations to the governor within one hundred eighty days of receipt by the council of such an application, or a later time as is mutually agreed by the council and the applicant.

(2) If the council recommends approval of an application for certification, it shall also submit a draft certification agreement with the report. The council shall include conditions in the draft certification agreement to implement the provisions of this chapter, including, but not limited to, conditions to protect state or local governmental or community interests affected by the construction or operation of the energy facility, and conditions designed to recognize the purpose of laws or ordinances, or rules or regulations promulgated thereunder, that are preempted or superseded pursuant to RCW 80.50.110 as now or hereafter amended.

((~~(2)~~)) (3)(a) Within sixty days of receipt of the council's report the governor shall take one of the following actions:

((~~(a)~~)) (i) Approve the application and execute the draft certification agreement; or

((~~(b)~~)) (ii) Reject the application; or

((~~(c)~~)) (iii) Direct the council to reconsider certain aspects of the draft certification agreement.

(b) The council shall reconsider such aspects of the draft certification agreement by reviewing the existing record of the application or, as necessary, by reopening the adjudicative proceeding for the purposes of receiving additional evidence. Such reconsideration shall be conducted expeditiously. The council shall resubmit the draft certification to the governor incorporating any amendments deemed necessary upon reconsideration. Within sixty days of receipt of such draft certification agreement, the governor shall either approve the application and execute the certification agreement or reject the application. The certification agreement shall be binding upon execution by the governor and the applicant.

((~~(3)~~)) (4) The rejection of an application for certification by the governor shall be final as to that application but shall not preclude submission of a subsequent application for the same site on the basis of changed conditions or new information.

NEW SECTION. **Sec. 201.** (1) A facility subject to closure under either RCW 80.80.040(3)(c) or a memorandum of agreement under section 106 of this act, or both, must provide the department of ecology with a plan for the closure and postclosure of the facility at least twenty-four months prior to facility closure or twenty-four months prior to start of decommissioning work, whichever is earlier. This plan must be consistent with the rules established by the energy facility site evaluation council for site restoration and preservation applicable to facilities subject to a site certification agreement under chapter 80.50 RCW and include but not be limited to:

(a) A detailed estimate of the cost to implement the plan based on the cost of hiring a third party to conduct all activities;

(b) Demonstrating financial assurance to fund the closure and postclosure of the facility and providing methods by which this assurance may be demonstrated;

(c) Methods for estimating closure costs, including full site reclamation under all applicable federal and state clean-up standards; and

(d) A decommissioning and site restoration plan that addresses restoring physical topography, cleanup of all hazardous substances on

the site, potential future uses of the site following restoration, and coordination with local and community plans for economic development in the vicinity of the site.

(2) All cost estimates in the plan must be in current dollars and may not include a net present value adjustment or offsets for salvage value of wastes or other property.

(3) Adoption of the plan and significant revisions to the plan must be approved by the department of ecology.

NEW SECTION. **Sec. 202.** (1) A facility subject to closure under either RCW 80.80.040(3)(c) or a memorandum of agreement under section 106 of this act, or both, must guarantee funds are available to perform all activities specified in the decommissioning plan developed under section 201 of this act. The amount must equal the cost estimates specified in the decommissioning plan and must be updated annually for inflation. All guarantees under this section must be assumed by any successor owner, parent company, or holding company.

(2) The guarantee required under subsection (1) of this section may be accomplished by letter of credit, surety bond, or other means acceptable to the department of ecology.

(3) The issuing institution of the letter of credit must be an entity that has the authority to issue letters of credit and whose letter of credit operations are regulated by a federal or state agency. The surety company issuing a surety bond must, at a minimum, be an entity listed as an acceptable surety on federal bonds in circular 570, published by the United States department of the treasury.

(4) A qualifying facility that uses a letter of credit or a surety bond to satisfy the requirements of this act must also establish a standby trust fund as a means to hold any funds issued from the letter of credit or a surety bond. Under the terms of the letter of credit or a surety bond, all amounts paid pursuant to a draft from the department of ecology must be deposited by the issuing institution directly into the standby trust fund in accordance with instructions from the department of ecology. This standby trust fund must be approved by the department of ecology.

(5) The letter of credit or a surety bond must be irrevocable and issued for a period of at least one year. The letter of credit or a surety bond must provide that the expiration date will be automatically

extended for a period of at least one year unless, at least one hundred twenty days before the current expiration date, the issuing institution notifies both the qualifying facility and the department of ecology of a decision not to extend the expiration date. Under the terms of the letter of credit, the one hundred twenty days will begin on the date when both the qualifying plant and the department of ecology have received the notice, as evidenced by certified mail return receipts or by overnight courier delivery receipts.

(6) If the qualifying facility does not establish an alternative method of guaranteeing decommissioning funds are available within ninety days after receipt by both the qualifying facility plant and the department of ecology of a notice from the issuing institution that it has decided not to extend the letter of credit beyond the current expiration date, the department of ecology must draw on the letter of credit or a surety bond. The department of ecology must approve any replacement or substitute guarantee method before the expiration of the ninety-day period.

(7) If a qualifying facility elects to use a letter of credit as the sole method for guaranteeing decommissioning funds are available, the face value of the letter of credit must meet or exceed the current inflation-adjusted cost estimate. If a qualifying facility elects to use a surety bond as the sole method for guaranteeing decommissioning funds are available, the penal sum of the surety bond must meet or exceed the current inflation-adjusted cost estimate.

(8) A qualifying facility must adjust the decommissioning costs and financial guarantees annually for inflation and may use an amendment to increase the face value of a letter of credit or a surety bond each year to account for this inflation. A qualifying facility is not required to obtain a new letter of credit or a surety bond to cover annual inflation adjustments.

NEW SECTION. **Sec. 203.** Sections 201 and 202 of this act constitute a new chapter in Title 80 RCW.

Sec. 301. RCW 43.160.076 and 2008 c 327 s 8 are each amended to read as follows:

(1) Except as authorized to the contrary under subsection (2) of this section, from all funds available to the board for financial

assistance in a biennium under this chapter, the board shall approve at least seventy-five percent of the first twenty million dollars of funds available and at least fifty percent of any additional funds for financial assistance for projects in rural counties.

(2) If at any time during the last six months of a biennium the board finds that the actual and anticipated applications for qualified projects in rural counties are clearly insufficient to use up the allocations under subsection (1) of this section, then the board shall estimate the amount of the insufficiency and during the remainder of the biennium may use that amount of the allocation for financial assistance to projects not located in rural counties.

(3) The board shall solicit qualifying projects to plan, design, and construct public facilities needed to attract new industrial and commercial activities in areas impacted by the closure or potential closure of large coal-fired electric generation facilities, which for the purposes of this section means a facility that emitted more than one million tons of greenhouse gases in any calendar year prior to 2008. The projects should be consistent with any applicable plans for major industrial activity on lands formerly used or designated for surface coal mining and supporting uses under RCW 36.70A.368. When the board receives timely and eligible project applications from a political subdivision of the state for financial assistance for such projects, the board from available funds shall give priority consideration to such projects.

NEW SECTION. **Sec. 302.** A new section is added to chapter 43.155 RCW to read as follows:

The board shall solicit qualifying projects to plan, design, and construct public works projects needed to attract new industrial and commercial activities in areas impacted by the closure or potential closure of large coal-fired electric generation facilities, which for the purposes of this section means a facility that emitted more than one million tons of greenhouse gases in any calendar year prior to 2008. The projects should be consistent with any applicable plans for major industrial activity on lands formerly used or designated for surface coal mining and supporting uses under RCW 36.70A.368. When the board receives timely and eligible project applications from a

political subdivision of the state for financial assistance for such projects, the board from available funds shall give priority consideration to such projects.

NEW SECTION. **Sec. 303.** A new section is added to chapter 80.04 RCW to read as follows:

The legislature finds that an electrical company's acquisition of coal transition power helps to achieve the state's greenhouse gas emission reduction goals by effecting an orderly transition to cleaner fuels and supports the state's public policy.

NEW SECTION. **Sec. 304.** A new section is added to chapter 80.04 RCW to read as follows:

(1) On the petition of an electrical company, the commission shall approve or disapprove a power purchase agreement for acquisition of coal transition power, as defined in RCW 80.80.010, and the recovery of related acquisition costs. No agreement for an electrical company's acquisition of coal transition power takes effect until it is approved by the commission.

(2) Any power purchase agreement for the acquisition of coal transition power pursuant to this section must provide for modification of the power purchase agreement to the satisfaction of the parties thereto in the event that a new or revised emission or performance standard or other new or revised operational or financial requirement or limitation directly or indirectly addressing greenhouse gas emissions is imposed by state or federal law, rules, or regulatory requirements. Such a modification to a power purchase agreement agreed to by the parties must be reviewed and considered for approval by the commission, considering the circumstances existing at the time of such a review, under procedures and standards set forth in this section. In the event the parties cannot agree to modification of the power purchase agreement, either party to the agreement has the right to terminate the agreement if it is adversely affected by this new standard, requirement, or limitation.

(3) When a petition is filed, the commission shall provide notice to the public and potentially affected parties and set the petition for hearing as an adjudicative proceeding under chapter 34.05 RCW. Any party may request that the commission expedite the hearing of that

petition. The hearing of such a petition is not considered a general rate case. The electrical company must file supporting testimony and exhibits together with the power purchase agreement for coal transition power. Information provided by the facility owner to the purchasing electrical company for evaluating the costs and benefits associated with acquisition of coal transition power must be made available to other parties to the petition under a protective order entered by the commission. An administrative law judge of the commission may enter an initial order including findings of fact and conclusions of law, as provided in RCW 80.01.060(3). The commission shall issue a final order that approves or disapproves the power purchase agreement for acquisition of coal transition power within one hundred eighty days after an electrical company files the petition.

(4) The commission must approve a power purchase agreement for acquisition of coal transition power pursuant to this section only if the commission determines that, considering the circumstances existing at the time of such a review: The terms of such an agreement provide adequate protection to ratepayers and the electrical company during the term of such an agreement or in the event of early termination; the resource is needed by the electrical company to serve its ratepayers and the resource meets the need in a cost-effective manner as determined under the lowest reasonable cost resource standards under chapter 19.280 RCW, including the cost of the power purchase agreement plus the equity component as determined in this section. As part of these determinations, the commission shall consider, among other factors, the long-term economic risks and benefits to the electrical company and its ratepayers of such a long-term purchase.

(5) If the commission has not issued a final order within one hundred eighty days from the date the petition is filed, or if the commission disapproves the petition, the power purchase agreement for acquisition of coal transition power is null and void. In the event the commission approves the agreement upon conditions other than those set forth in the petition, the electrical company has the right to reject the agreement.

(6)(a) Upon commission approval of an electrical company's power purchase agreement for acquisition of coal transition power in accordance with this section, the electrical company is allowed to earn the equity component of its authorized rate of return in the same

manner as if it had purchased or built an equivalent plant and to recover the cost of the coal transition power under the power purchase agreement. Any power purchase agreement for acquisition of coal transition power that earns a return on equity may not be included in an imputed debt calculation for setting customer rates.

(b) For purposes of determining the equity value, the cost of an equivalent plant is the least cost purchased or self-built electric generation plant with equivalent capacity. In determining the least cost plant, the commission may rely on the electrical company's most recent filed integrated resource plan. The cost of an equivalent plant, in dollars per kilowatt, must be determined in the original process of commission approval for each power purchase agreement for coal transition power.

(c) The equivalent plant cost determined in the approval process must be amortized over the life of the power purchase agreement for acquisition of coal transition power to determine the recovery of the equity value.

(d) The recovery of the equity component must be determined and approved in the review process set forth in this section. The approved equity value must be in addition to the approved cost of the power purchase agreement.

(7) Authorizing recovery of costs under a power purchase agreement for acquisition of coal transition power does not prohibit the commission from authorizing recovery of an electrical company's acquisition of capacity resources for the purpose of integrating intermittent power or following load.

(8) Neither this act nor the commission's approval of a power purchase agreement for acquisition of coal transition power that includes the ability to earn the equity component of an electrical company's authorized rate of return establishes any precedent for an electrical company to receive an equity return on any other power purchase agreement or other power contract.

(9) For purposes of this section, "power purchase agreement" means a long-term financial commitment as defined in RCW 80.80.010(15)(b).

(10) This section expires December 31, 2025.

Sec. 305. RCW 19.280.030 and 2006 c 195 s 3 are each amended to read as follows:

Each electric utility must develop a plan consistent with this section.

(1) Utilities with more than twenty-five thousand customers that are not full requirements customers shall develop or update an integrated resource plan by September 1, 2008. At a minimum, progress reports reflecting changing conditions and the progress of the integrated resource plan must be produced every two years thereafter. An updated integrated resource plan must be developed at least every four years subsequent to the 2008 integrated resource plan. The integrated resource plan, at a minimum, must include:

(a) A range of forecasts, for at least the next ten years, of projected customer demand which takes into account econometric data and customer usage;

(b) An assessment of commercially available conservation and efficiency resources. Such assessment may include, as appropriate, high efficiency cogeneration, demand response and load management programs, and currently employed and new policies and programs needed to obtain the conservation and efficiency resources;

(c) An assessment of commercially available, utility scale renewable and nonrenewable generating technologies <u>including a comparison of the benefits and risks of purchasing power or building new resources</u>;

(d) A comparative evaluation of renewable and nonrenewable generating resources, including transmission and distribution delivery costs, and conservation and efficiency resources using "lowest reasonable cost" as a criterion;

(e) The integration of the demand forecasts and resource evaluations into a long-range assessment describing the mix of supply side generating resources and conservation and efficiency resources that will meet current and projected needs at the lowest reasonable cost and risk to the utility and its ratepayers; and

(f) A short-term plan identifying the specific actions to be taken by the utility consistent with the long-range integrated resource plan.

(2) All other utilities may elect to develop a full integrated resource plan as set forth in subsection (1) of this section or, at a minimum, shall develop a resource plan that:

(a) Estimates loads for the next five and ten years;

(b) Enumerates the resources that will be maintained and/or acquired to serve those loads; and

(c) Explains why the resources in (b) of this subsection were chosen and, if the resources chosen are not renewable resources or conservation and efficiency resources, why such a decision was made.

(3) An electric utility that is required to develop a resource plan under this section must complete its initial plan by September 1, 2008.

(4) Resource plans developed under this section must be updated on a regular basis, at a minimum on intervals of two years.

(5) Plans shall not be a basis to bring legal action against electric utilities.

(6) Each electric utility shall publish its final plan either as part of an annual report or as a separate document available to the public. The report may be in an electronic form.

NEW SECTION. **Sec. 306.** A new section is added to chapter 80.70 RCW to read as follows:

(1) An applicant for a natural gas-fired generation plant to be constructed in a county with a coal-fired electric generation facility subject to RCW 80.80.040(3)(c) is exempt from this chapter if the application is filed before December 31, 2025.

(2) For the purposes of this section, an applicant means the owner of a coal-fired electric generation facility subject to RCW 80.80.040(3)(c).

(3) This section expires December 31, 2025, or when the station-generating capability of all natural gas-fired generation plants approved under this section equals the station-generating capability from a coal-fired electric generation facility subject to RCW 80.80.040(3)(c).

NEW SECTION. **Sec. 307.** If any provision of this act or its application to any person or circumstance is held invalid, the remainder of the act or the application of the provision to other persons or circumstances is not affected.

Passed by the Senate April 21, 2011.
Passed by the House April 11, 2011.
Approved by the Governor April 29, 2011.
Filed in Office of Secretary of State April 29, 2011.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-119:
2023 Bonneville "White Book"

BONNEVILLE POWER ADMINISTRATION

2023 Pacific Northwest Loads and Resources Study

April 2023





Department of Energy

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

April 20, 2023

In reply refer to: PGPR-5

Dear Interested Parties:

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

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

New for this white book, firm energy planning is based off the tenth percentile of the Tier One System Firm Critical Output (T1SFCO), previously water year 1937. Moving to percentile approach helps avoid any anomaly observed in a single water year. As a prime example, January 1937 being the worst monthly streamflow on record, comparison between this white book and the 2022 White Book, particularly in January 120-Hr (MW) metric, displays the results of this change.

This 2023 White Book presents Federal system and the region's load obligations, contracts, and resources as of December 2022 for operating years (OY) 2024 through 2033. The 2023 White Book includes the following studies:

- **Federal System Analysis**—forecast of Federal system firm loads and resources based on expected load obligations and different levels of generating resources that vary by different energy planning. The results are summarized below:
  - Annual Energy Surplus/Deficits: Under firm; the Federal system is projected to have annual energy deficits across the study period, ranging from deficits of 18 aMW to 424 aMW. Except for the first year of the study period, these annual energy deficit projections are greater than those projected in the 2022 White Book. Under median water conditions; the Federal system is projected to have annual energy surpluses through the study period.
  - January 120-Hour Capacity Surplus/Deficits: Under firm water conditions; the Federal system is projected to have January 120-Hour capacity surpluses through most of the study period with the only deficit in OY2033. Surpluses starting at 414 MW for the first year gradually decline to a deficit in the last year of 123 MW. These 120-Hour capacity results are different than those projected in the 2022 White Book largely due to the change in firm water conditions planning. . Under median water conditions; the Federal system is projected to have January 120-Hour capacity surpluses over the study period.

- **PNW Regional Analysis**—forecast of regional firm loads and resources, based on expected retail loads and different levels of generating resources that vary by water conditions. The decommissioning of existing resources, the availability of uncommitted PNW Independent Power Producer (IPP) generation, and new resource additions are key variables in the results of this analysis. The results are summarized below:
    - Annual Energy Surplus/Deficits: Under firm water conditions; the PNW region is projected to have an annual energy surplus as large as 2,316 aMW in OY 2024, slowly decreasing to a deficit of 61 aMW by OY 2033. These annual energy projections are more surplus throughout the study period than was forecasted in the 2022 White Book. Under median water conditions; the PNW region would see even larger energy surpluses over the study horizon.
    - January 120-Hour Capacity Surplus/Deficits: Under firm water conditions; the PNW region is projected to have January 120-Hour capacity deficits over most of the study period ranging from 774 MW to 3,506 MW, except for the first two years (OY 2024 and OY 2025) which are slightly surplus. These deficit projections are much less than those shown in the 2022 White Book. Under median water conditions; the PNW region has January 120-Hour capacity surpluses through the final year of this study.

BPA is currently starting the development of its 2024 Resource Program designed to evaluate long-term power resources acquisition strategies. Many factors contribute to the uncertainty of the longer term resources outlook for the region; such as resource retirements and development, resource adequacy and the efforts surrounding it, carbon free resource requirements, and the most recent Climate Resiliency efforts. As with resources, there is also much uncertainty with loads including the potential for electrification. The 2023 White Book is available on BPA's website: *https://www.bpa.gov/energy-and-services/power/resource-planning* or from BPA's Visitor Center, which you can reach toll-free at 800-622-4520 (or 503-230-4636). Details regarding regional loads, contracts, and generating resources are available upon request. Available report list can be found in Appendix A.

Please send questions and/or comments to Steve Bellcoff (503) 230-3319.

Sincerely,

ROBERT PETTY Digitally signed by ROBERT PETTY
Date: 2023.04.20 13:12:12 -07'00'

Robert Petty
Manager, Power and Operations Planning

Enclosure

2023 PACIFIC NORTHWEST LOADS AND RESOURCES STUDY

The White Book

BONNEVILLE POWER ADMINISTRATION
April 2023

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

The Dalles Dam is located roughly 190 miles upstream from the mouth of the Columbia River and a couple of miles east of the City of The Dalles. It was constructed between 1952 and 1957 by the United States Army Corps of Engineers, and was the federal government's effort to develop hydropower and navigation potential of the Columbia River after World War II.

The Dalles Dam was constructed after the Bonneville Dam in 1937 and McNary Dam in 1945. In addition to meeting the electrical power demand, a newer navigation lock would replace Corps' original and smaller Dalles-Celilo Canal.

For more history on The Dalles Dam, please visit The Dalles Dam (oregonencyclopedia.org).

ACKNOWLEDGMENTS

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

Bonneville Power Administration

Generation Asset Management:

Long Term Power Planning Group
Regional Coordination Group
Operational Planning Group

Customer Support Services:

Load Forecasting and Analysis Group

Bulk Marketing and Transmission Services:

Long Term Sales and Purchasing Group

NW Requirements Marketing:

Office of General Counsel

Pacific Northwest Utilities Conference Committee

Northwest Power & Conservation Council

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Section 1: Summary

Planning Context

The Pacific Northwest Loads and Resources Study (commonly referred to as the "White Book") is a planning document produced by the Bonneville Power Administration (Bonneville) that presents its projection of load and resource conditions for the upcoming 10-year period (operating year 2024 through 2033). The White Book includes analysis of Bonneville's forecasts of expected power obligations and resource generation for both the Federal system and the Pacific Northwest (PNW) region as a whole. The information contained in the White Book is used for: 1) long-term planning studies for Bonneville; 2) planning studies for the Columbia River Treaty (Treaty); and 3) as a published record of information and data for customers and other regional planning entities. The White Book is not used to guide day-to-day operations of the Federal Columbia River Power System (FCRPS).

Bonneville's White Book traditionally focuses on long-term deterministic power planning for the Federal system and the PNW region. Bonneville's Federal System Analysis calculates the Federal system load and resource balance by comparing expected Federal system loads and contract obligations to forecasted Federal system resource generation and contract purchases. In the same manner, Bonneville's PNW regional analysis calculates the PNW regional load and resource balance by comparing expected regional retail loads and contract obligations to forecasted regional resource generation and contract purchases. Hydropower resources for the Federal system and PNW region include variability by incorporating a variety of generation forecasts, associated with streamflows from the most recent 30-historical water conditions[1] of the 2020 Modified Flows. These deterministic analyses are modeled by operating year (OY[2]), defined as August-July, to be consistent with regional coordination of the Treaty and PNCA. Results are presented in: 1) annual and monthly energy, expressed in average megawatts (aMW); and 2) monthly peak capacity, presented in 120-Hour peak megawatts (MW). The Federal System Analysis is presented in Section 2, and the Pacific Northwest Regional Analysis is presented in Section 3.

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

The 2023 White Book is published as a single summary document. Beginning with the 2022 White Book the Technical Appendices are no longer published along with the summary document, rather, Appendix A at the end of this summary document contains the list of reports previously included in the Technical Appendices, and those reports are available upon request. Please contact Steve Bellcoff, srbellcoff@bpa.gov, (503) 230-3319 with requests.

The total retail load, contract, and generation forecasts used in this study were updated as of December 31, 2022. The 2023 White Book supersedes the 2022 White Book.

Load Obligations

The load obligations for the Federal system and PNW region contain multiple components in this study, and load obligation forecasts are categorized as follows: 1) Total Retail Loads (TRL), defined as each individual

[1] Additional details please refer to Climate Change and the FCRPS (including the Climate Change Resiliency effort)

[2] Operating Year (OY) is the time frame August 1 through July 31. For example, OY 2024 is August 1, 2023 through July 31, 2024.

utility's retail electric power consumption on its system, including electrical system losses; and 2) contract obligations, which include reported PNW utility long-term contract sales within the PNW region (Intra-Regional Transfers *(Out)*) and outside the PNW region (Exports). Contract obligations also include Federal system power sales delivered to Federal agencies, public bodies, cooperative, and tribal utility preference customers as stated under section 5 of the Northwest Electric Power Planning and Conservation Act (NW Power Act), 16 U.S.C. 839 et seq., (December 5, 1980).

Forecasts of the regional TRL and Federal system load obligations are produced by Bonneville's Agency Load Forecasting (ALF) system. ALF forecasts are completed for individual PNW entities under one of two approaches; 1) using statistical approaches that are based on time-series-based regressions that follow the fundamental assumption that historical retail electricity consumption patterns will continue into the future, 2) statistically adjusted end-use models. The statistically adjusted end-use models include calculated indexes for heating equipment, cooling equipment, and other equipment. ALF forecasts also assume normal weather conditions and do not include any explicit adjustments for the impacts of climate change, however they do use temperature normals based on recent history in order to be consistent with recent climate trends. Contract obligations not associated with Bonneville's Regional Dialogue contracts follow individual contract terms through the life of the contract and are not assumed to be renewed. All Federal system load and contract obligations are assumed to be firm and served by Bonneville regardless of weather, water, or economic conditions.

Resource Types

Regional resources consist of "on the ground" generating facilities and contract purchases that are used to serve retail loads. PNW resources (including the Federal system) are predominantly hydro based, therefore, generation levels can vary greatly both from month-to-month and from year-to-year. This analysis classifies resources as; 1) Hydro resources, which include regulated, independent, and small hydro projects; 2) Non-hydro renewable resources, which include wind, solar, and other projects; 3) Thermal resources, which include nuclear, coal, natural gas, petroleum, biofuel and cogeneration projects; and 4) Contract purchases, which include reported PNW utility long-term contract purchases from within the PNW region (Intra-Regional Transfers *(In)*) and from outside the PNW region (Imports). The generation forecasts for these resources are provided by Bonneville models or from the project owners, and those are described below.

Hydro resources

- Regulated Hydro: Regulated hydro projects mainly consist of PNW Columbia River Basin hydro power projects for which the operation and generating capability is hydraulically coordinated to meet power and non-power requirements. Bonneville forecasts the coordinated energy and capacity production from these hydro power projects using its Hydrosystem Simulator (HYDSIM) model. The HYDSIM model takes into account individual project operating characteristics and conditions, to determine energy production expected on a project-by-project basis. Generation forecasts for these projects incorporate the month-to-month power and non-power requirements under each of the 30-historical streamflow conditions of record, 1989 through 2018. The HYDSIM model is described further in the Hydro Resource Modeling section.
- Independent Hydro: Independent hydro projects include those hydro projects whose generation output typically varies by water condition but are not operated as part of the coordinated Columbia River Basin system. Independent hydro generation forecasts can vary month-to-month for energy and capacity, and are developed and provided by individual project owners/operators for the same 30-historical water conditions as the Regulated Hydro projects.

- Small Hydro: Small hydro project generation forecasts are either provided by individual project owners or are based on historical actual generation. These generation forecasts can vary month-to-month but are not assumed to vary by water condition.

Non-hydro renewable resources

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

Thermal resources

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

Contract purchases

- Contract Purchases/Imports: Contract purchases include signed Federal system purchases and regional contract purchases with power delivered to PNW entities reported by utilities publically and in data submittals. These purchases are treated as resources in both the Federal system and regional analyses. Purchases between entities within the PNW are called Intra-regional Transfers *(In)* and purchases from entities outside the PNW are called Imports. With the exception of contracts associated with the Treaty, all existing Federal system and regional contract purchases follow individual contract terms through the life of the contract and are not assumed to be renewed. Treaty power deliveries are assumed to be in place through the study period.

Adjustments to Resources

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

- Operating and Balancing Reserves: Operating reserves consist of both spinning and non-spinning contingency reserves that respond to the unforeseen loss of a resource, which are calculated by summing 3 percent of forecast load and 3 percent of forecast generation. Balancing reserves consist of regulating, load following, and imbalance reserves that are dedicated to maintaining within-hour load and resource balance. The modeling of reserves, including those for wind integration, is described in the Hydro Resources Modeling section below. The reserve forecasts included in this 2023 White Book are modeled consistent with those used in Bonneville's BP-24 Initial Rates Proposal.

- Transmission Losses: During the transmission of power to load centers some of the electrical energy is lost, usually in the form of heat, which is known as transmission losses. Transmission losses are calculated on a monthly basis and vary by generation, based on the sum of all generation and contract purchase forecasts. The transmission loss factor has several components that combine to give the estimate of losses typically associated with Federal system generation: (1) step-up transformers from generation to the high-voltage transmission network, (2) high-voltage network transmission, (3) transfers to Federal loads over non-Federal transmission systems, and (4) step-down transformers from high-voltage transmission to low-voltage delivery. The Federal system transmission loss factors used in this Study are:
    - Energy is 3.11 percent, September through May and 3.16 percent, June through August.
    - Capacity is 3.16 percent, September through May and 3.21 percent, June through August.

Hydro Resources Modeling

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

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

- National Marine Fisheries Service 2008 Willamette BiOp (July 11, 2008)
- 2020 Columbia River System Operations Environmental Impact Statement (CRSO EIS), (Sept. 28, 2020)
- 2020 NOAA Fisheries Federal Columbia River Power System Biological Opinion (2020 NMFS BiOp) (July 24, 2020)
- 2020 US Fish and Wildlife Service Biological Opinion (November 12, 2019)

The Pacific Northwest Coordination Agreement (PNCA) coordinates the planning and operation of the members' hydroelectric power projects in the PNW. PNCA project owners provide physical plant data as well as power and non-power constraints in an annual data submittal to the Western Power Pool. Bonneville incorporates this data into HYDSIM to simulate the coordinated operation of the PNW hydro system. This coordination agreement expires on September 15, 2024. PNCA project owners are currently engaging in discussions regarding PNCA expiration and future coordination.

The construction of three large storage projects in Canada under the Treaty between the United States and Canada enhanced the volume of storage in the Columbia River Basin. These projects provide downstream power benefits by increasing the firm power generating capability of U.S. hydro projects. The Treaty calls for

[3] 2020 Modified Flows

an Assured Operating Plan (AOP) to be completed six years prior to each operating year, and allows a Detailed Operating Plan (DOP) to be completed, if agreed upon, in the year prior to the operating year. The Canadian project operations simulated in HYDSIM are based on the best available information from the Treaty planning and coordination process. Canadian operations included in this 2023 White Book are based on the official 2022 AOP studies, with additional modifications that reflect updates expected in the official DOP studies.

Both the United States and Canada have the ability to terminate most of the provisions of the Treaty any time after September 16, 2024, with a minimum of 10 years advance notice. Neither Canada nor the United States have provided notice of termination; therefore, this study assumes the Treaty continues throughout the study period including current flood risk management provisions.

Bonneville has other operational agreements with Canada that are not part of the Treaty. One operational agreement is the Non-Treaty Storage Agreement (NTSA) that allows additional shaping of Columbia River flows for power and fish operations by utilizing storage not specified by the Treaty from Canadian reservoirs. The NTSA allows water to be released from Canadian project storage during the spring of dry years. The NTSA also allows water to be stored in the spring during years when the spring flow targets from the 2008 NOAA BiOp would be met with a subsequent release of water in the summer. These operations have been included in this study based on the NTSA signed with British Columbia Hydro in April 2012, which expires on September 15, 2024[4].

Balancing reserves, both incremental and decremental, reduce the ability to shape Federal system generation. Incremental reserves are modeled by reducing the generation capability of projects. In this study, the impacts of incremental reserves are shown as a reduction in the capacity analyses and are categorized as operating and balancing reserves. Decremental reserves are not specifically reported in this study as they do not cause a limitation in generation capability.

Firm Water Planning: To ensure sufficient generation to meet load, Bonneville bases its resource planning on firm water conditions or firm expected generation. Firm water conditions are defined as when the PNW hydro system would produce the least amount of power while taking into account the historical streamflow record, power and non-power operating constraints, the planned operation of non-hydro resources, and system load requirements. For operational purposes, Bonneville considers firm water conditions to be the tenth percentile of the monthly Tier One System Firm Critical Output (T1SFCO) system results. The percentile approach eliminates the anomalies observed in any single water year, e.g. 1937; it also aligns with metrics used in Bonneville's Resource Program. For additional details, please refer to Bonneville's Climate Change Resiliency Letter to the region (June 6, 2022).

Variability of Hydro Generation: The generating capability of Federal system and regional hydro projects depends on the amount of water flowing through the facilities, the physical capacity of the facilities, any flow or operating requirements pursuant to biological opinions, and other operating limitations. Water conditions cause hydro generation to vary greatly year to year depending on factors such as precipitation, snowpack, and temperature. Project-level generation forecasts for regulated hydro resources are produced using HYDSIM for each of the 30 historical streamflow conditions of record, which are based on the period from 1989 through 2018. In addition, Federal independent hydro project generation was updated by the Army Corps of Engineers, The Bureau of Reclamation, and other project owners incorporating the 2020 modified flows and up to date project operations.

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

[4] Bonneville acknowledges that there are ongoing discussions regarding the continuation of both the NTSA and the PNCA.

- Firm water: tenth percentile (P10) of system generation by month with the most recent historical 30-year streamflow conditions, it represents the firm water condition for energy and capacity of the hydro system.
- Median water: 50th percentile (P50) of system generation by month of the most recent historical 30- year streamflow conditions, it represents the exact middle value of generation for energy and capacity.
- High water: 90th percentile (P90) of system generation by month of the most recent historical 30- year streamflow conditions, this represents the high generation scenario of the energy and capacity of the hydro system.

Generation percentile by month for each OY in the study is included in Exhibit 4-6.

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

For hydro resources, the 120-Hour capacity forecasts are created by evaluating hourly generation from RiverWare over a specific period of time. This capacity metric is defined as the average generation forecasts from the 6 highest heavy load hours per day, 5 days per week, for 4 weeks per month (6 x 5 x 4 = 120 hours). While available, the White Book does not include 1-Hour hydro capacity forecasts because it does not represent a sustainable generation but rather a single hour peak, meaning it does not consider the ability of the hydro system to sustain generation levels over a multiple hour period. January 120-hr capacity has been the most constrained metric historically, a prime example for avoiding anomalies in a single water year, January 1937 was the extreme month resulted in one percentile of the 80-water year generation distribution from the 2022 White Book. Comparisons between the 2022 White Book, which uses 1937 as firm critical condition, and this White Book, P10, will display the large difference mostly due to the anomaly of 1937 in both Federal and Regional systems.

The 120-Hour capacity analysis presented in this study better reflects the ability of the hydro system to sustain a generating peak energy level to meet load obligations throughout each month. The 120-Hour capacity presented in this analysis can be expressed as either capacity in megawatts (MW) or energy over super peak load hours in average megawatts.

Notable Updates

The 2023 White Book includes updated forecasts of Federal system power sales contract (PSC) obligations, PNW regional Total Retail Loads, contract purchases, and generation as of December 1, 2022, including:

- Updates associated with BPA's Climate Change Resiliency effort, including using the recent 30 year historical record and monthly P10 as Firm conditions.
- Three customers elected to change product elections from BPA's Slice Product to Load Following Product, and the new product election is reflected from October 1, 2024 across the study period.
- Updated retirement dates associated with planned thermal (coal) generation retirements.

Sources of Uncertainty

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

- Changes to hydro system operations in response to Endangered Species Act requirements or other environmental considerations;
- Changes to hydro system operations in response to court actions and/or operational agreements;
- Natural variations in weather affecting electrical power demand and streamflow runoff that affect hydroelectric power generation;
- Potential increases or decreases in retail and industrial loads due to changes in local, regional, and/or national economic conditions;
- Potential new large individual retail loads and/or other changes to major industrial operations;
- Potential service to new loads such as new customers or the Department of Energy's Richland vitrification plant operations;
- Potential future policy requirements at local, state, and federal levels regarding the amount and type of renewable resources, conservation standards, electric vehicle saturation, and/or carbon emissions;
- Fuel cost and availability, which may be affected by environmental factors or competing uses for industry, transportation, and import/export markets;
- Changes to operating limits on existing and future thermal resources;
- Changes to retirement dates associated with resources;
- Failures of resources to operate at anticipated times and/or output levels;
- Changes to Treaty obligations and/or operations;
- PNW entities' ability to purchase power from new and existing uncommitted regional resources to serve retail load;
- PNW entities' ability to purchase and transmit power from extra-regional import/export markets;
- Future climate change impacts to retail loads, streamflows, and resources.

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

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Section 2: Federal System Analysis

The Federal System Analysis provides a deterministic forecast of Federal system loads and resources over a 10-year period from OY 2024 through 2033. This analysis incorporates forecasts of the Federal system's firm requirements power sales contract (PSC) obligations, contract sales and purchases, and resource generation. This section presents firm Federal system load and resource forecasts for energy and 120-Hour capacity. The detailed components of the Federal system study are available upon request.

Load Obligations

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

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

Regional Dialogue CHWM PSC obligations to Public & Federal agency customers: In December 2008, Bonneville executed Regional Dialogue PSCs with public, cooperative, and tribal utilities, and federal agency customers. Bonneville is obligated to provide firm power deliveries from October 1, 2011, through September 30, 2028. Three types of products were offered to customers: Load Following, Slice/Block, and Block. Of the 134 customers who have signed Regional Dialogue Contracts; 121 are currently Load Following customers, 10 are Slice/Block customers, and three are Block customers. Three customers: Benton PUD, Grays Harbor PUD, and Pacific PUD recently switched from Slice/ Block customers to Load Following starting in the BP24 Rate Period and are now included in this study as Load Following customers.

Under the Regional Dialogue PSCs, customers must make periodic elections of how to serve their Above Rate Period High Water Mark (A-RHWM)[5] load by: 1) adding new non-Federal resources; 2) acquiring power from non-Federal resources; and/or 3) requesting Bonneville to supply additional power. The current customer elections have been set through fiscal year (FY) 2025, and this study assumes that the current elections continue through the study period. Based on this assumption, Federal system Regional Dialogue PSC obligation forecasts include elected and forecasted A-RHWM load for the study period. Table 2-1 presents the A-RHWM load included in Bonneville's obligations by FY, which are consistent with the BP-24 Initial Rate Proposal.

[5] "A Rate High Water Mark (RHWM) defines a public customer's maximum eligibility to purchase an amount of power service at Tier 1 Rate for a Rate Period, subject to limitation by the customer's New Requirement." (P.2 Regional Dialogue June 4, 2010)

Table 2-1

Federal System
Annual Above-Rate High Water Mark (A-RHWM) Obligations
FY 2025 through 2033

Energy (aMW)	2025	2026	2027	2028	2029	2030	2031	2032	2033
A-RHWM Obligations	382	408	434	460	495	516	536	549	575

IOU Load Service under Regional Dialogue PSCs: The six IOUs in the PNW region are Avista Corporation, Idaho Power Company, NorthWestern Energy Division of NorthWestern Corporation, PacifiCorp, Portland General Electric Company, and Puget Sound Energy, Inc. The PNW IOUs all signed Bonneville RD PSCs for FY 2011 through 2028; however, no IOUs have elected to take power service under these contracts and no net requirements power sales are assumed for the IOUs through the study period.

Direct Service Industrial (DSI) contracts: Bonneville has one DSI customer, Port Townsend Paper Corporation. Port Townsend Paper Corporation's contract with Bonneville expires on September 30, 2028. Federal system DSI deliveries are forecasted at 11 aMW and expected to remain at that level throughout the study period.

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

Treaty, Regional Dialogue PSC, and DSI power deliveries are assumed to remain in place through the study horizon. Bonneville's Other Contract Obligations follow individual contract terms and are not assumed to be renewed after expiration.

Firm Loads: The Federal system total firm load forecast shows a 2.50 percent average annual load growth over the study period. While Bonneville's forecast of PSC requirements load increases about 11 percent over the study period, Bonneville's Exports and Intra-Regional Transfers decrease due to the expiration of contracts throughout the study period. Other Contract Obligations that expire during the study period include Federal system power sales, and Federal system capacity sales. Overall, the total Federal system load obligations remain relatively flat on an annual basis over the study period. Relatively flat load growth is an expectation for the Federal system do to the nature of BPA's Regional Dialogue PSCs. While the study horizon continues past the end of Regional Dialogue contracts, and obligations are placed on BPA under the future Provider of Choice contracts is unknown at this time, the study assumes a continuation of Regional Dialogue PSC load levels for planning purposes.

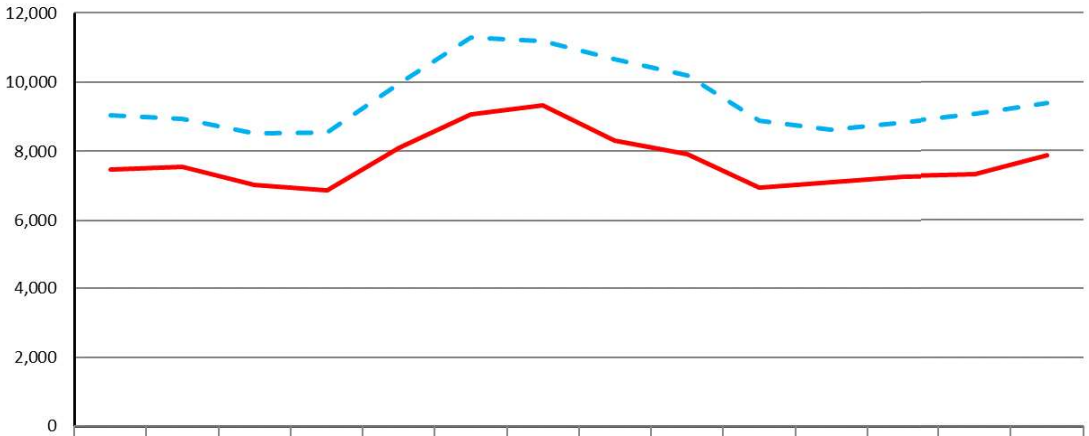
Conservation: The PSC obligation forecasts developed by ALF are expected load forecasts, which include conservation identified by individual Bonneville customers.

Bonneville loads can vary greatly throughout the year. At a high level, Bonneville forecasts represent higher loads in the winter (November through February) due to lower temperatures that increase heating loads, and lower loads during the spring, early summer and early fall when temperatures are mild. July and August loads

tend to be slightly higher than the rest of the summer due to increasing PNW air conditioning loads. Table 2-2, here, illustrates the monthly shape of the forecasted Federal system firm load obligations for OY 2024. Monthly energy and 120-Hour capacity are projected to maintain a similar shape over the study period.

Table 2-2

Federal System
Monthly Energy and 120-Hour Capacity Load Obligations
OY 2024 Firm Water Condition

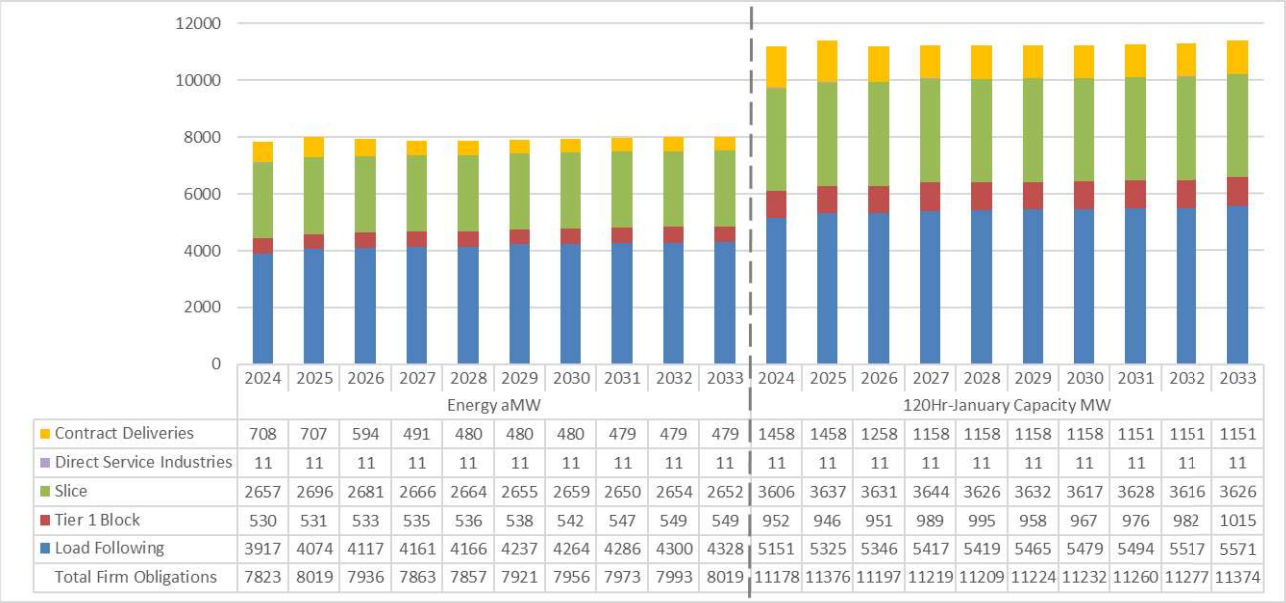


	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	7,467	7,564	7,022	6,877	8,095	9,057	9,338	8,321	7,912	6,955	7,106	7,267	7,314	7,862
120 Hour Cap (MW)	9,039	8,926	8,514	8,535	9,951	11,301	11,178	10,670	10,205	8,891	8,631	8,829	9,072	9,371

On an annual basis Bonneville loads vary across the study period. Table 2-3, next, illustrates the annual Federal system firm load obligations for OY2024 through 2033.

Table 2-3

Federal System
Annual Energy and 120-Hour Capacity Load Obligations
OY 2024 through 2033 Firm Water Condition
By Category



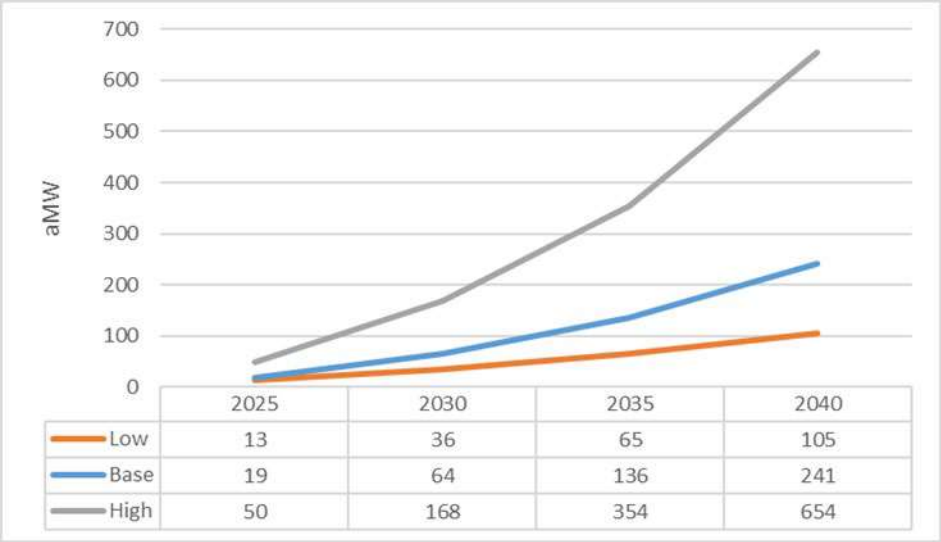
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	Energy aMW										120Hr-January Capacity MW									
Contract Deliveries	708	707	594	491	480	480	480	479	479	479	1458	1458	1258	1158	1158	1158	1158	1151	1151	1151
Direct Service Industries	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Slice	2657	2696	2681	2666	2664	2655	2659	2650	2654	2652	3606	3637	3631	3644	3626	3632	3617	3628	3616	3626
Tier 1 Block	530	531	533	535	536	538	542	547	549	549	952	946	951	989	995	958	967	976	982	1015
Load Following	3917	4074	4117	4161	4166	4237	4264	4286	4300	4328	5151	5325	5346	5417	5419	5465	5479	5494	5517	5571
Total Firm Obligations	7823	8019	7936	7863	7857	7921	7956	7973	7993	8019	11178	11376	11197	11219	11209	11224	11232	11260	11277	11374

Electrification in Load Obligations

While Bonneville's contractual load forecast includes a small increase in load resulting from electrification, the growing interest in electrification suggests a potential for significant load growth in the future and an area Bonneville will continue to monitor. Table 2-4, a re-print from 2022 White Book, presents Bonneville's view of the possible range of load growth resulting from electrification in customers' load. While this study includes the base forecasted load increases from the table, a range of possible customer load increase is presented. It is important to note that due to the tiered structure of Bonneville's Regional Dialogue PSCs, only a share of increased load may become a Bonneville obligation. These possible electrification increases are expected to result from electrical vehicle use and the increasing conversion to electric applications to reduce greenhouse gases.

Table 2-4

Federal System
Annual Energy – Electrification Load Obligation Increases
(Re-print from 2022 White Book)



	2025	2030	2035	2040
Low	13	36	65	105
Base	19	64	136	241
High	50	168	354	654

Resources

In the PNW, Bonneville is directed to market power from Federal hydroelectric projects and other resources acquired to meet firm power contractual obligations. Bonneville does not own generating resources, rather, Bonneville markets power from Federal resources and certain non-Federal generating resources whose output Bonneville has acquired under contracts. These resources and contract purchases are collectively called "Federal system resources" in this study. Federal system resources are currently comprised of: 1) Hydro resources, which include regulated, independent, and small hydro projects; 2) Non-hydro renewable resources, which include wind, solar, and other projects; 3) Thermal resources, which includes nuclear (Columbia Generating Station); and 4) Contract purchases, which include contract purchases from entities within the PNW region (Intra-Regional Transfers *(In)*) and from those outside the PNW region (Imports), including Non-Federal Canadian Entitlement Return power and transmission loss returns under Slice/Block contracts.

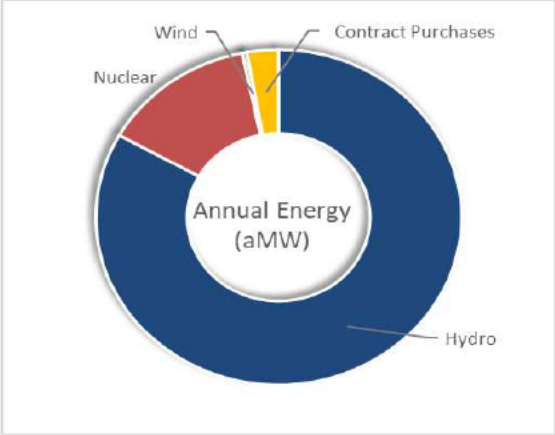
Federal System Resource Types: Table 2-5, summarizes Bonneville's resources and contract purchases available to meet the Federal system load obligations. For OY 2024, Federal system resources are forecast to produce 7,785 annual aMW of generation under Firm water conditions, with reserves and losses included.

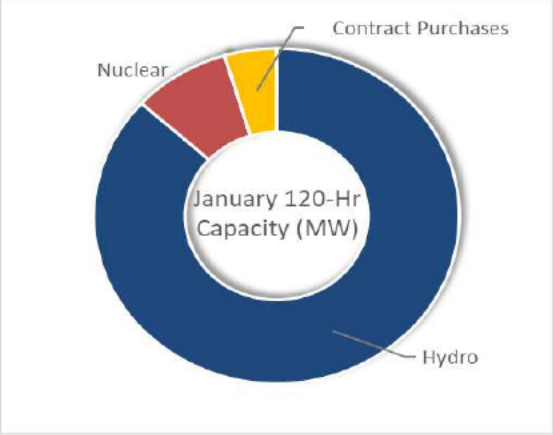
Table 2-5 [a/]

Federal System
Generation Forecast by Resource Type
OY 2024 Firm Water Conditions

Resource Type	Annual Energy (aMW)	Percent of Firm Energy	January 120-Hour Capacity (MW)[b/]	Percent of Capacity
Hydro	6,662	83%	11,828	88%
Nuclear	1,116	14%	1,178	9%
Wind	33	0.4%	0	0%
Other Renewables	0	0%	0	0%
Contract Purchases	227	3%	627	3%
Total Federal Resources	8,038	100%	13,633	100%

[a/] Any discrepancies in totals for figures portrayed in this table are due to rounding.
[b/] Federal resource estimates are before adjustments for reserves and transmission losses





Federal system resources are comprised of:

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

Federal system contract purchases: Bonneville purchases or receives power under a variety of contract arrangements from entities within the PNW region (Intra-Regional Transfers *(In)*) and from outside the PNW region (Imports), to meet Federal system load obligations. These contract purchases, presented in Table 2-7 are made up of: 1) power purchases, 2) power or energy exchange purchases, 3) power assigned to Bonneville under Treaty-related agreements, and 4) transmission loss returns under Slice/Block contracts. Bonneville's contract purchases are considered firm resources that are delivered to the Federal system regardless of weather, water, or economic conditions. Transmission loss returns capture the return of Slice/Block transmission losses to the Federal system as specified in the Slice/Block contracts, and these returns are also treated as Federal system resources. With the exception of deliveries from Treaty-related and Slice/Block contracts, each contract purchase follows specific delivery terms and expiration dates and is not assumed to be renewed. Treaty-related and Slice/Block contracts are assumed to remain in place through the study horizon.

Table 2-6

Federal System
Hydro Project Generation by Various Streamflow Conditions [6]
OY 2024

Project	Initial Service Date	Operator	Number of Units	Maximum Capacity [d/] (MW)	High [c/] Energy (aMW)	Median [c/] Energy (aMW)	Firm Energy [a/c/] (aMW)
Regulated Hydro							
1. Albeni Falls	1955	USACE	3	50	22.4	24.0	22.5
2. Bonneville [b/]	1938	USACE	18	1,221	674	535	397
3. Chief Joseph	1955	USACE	27	2,614	1,733	1,374	1,123
4. Dworshak	1974	USACE	3	465	277	203	170
5. Grand Coulee / GCL Pumping	1941	USBR	27	6,684	3,049	2,330	1,924
	1973		6	314			
6. Hungry Horse	1952	USBR	4	310	146	94	84
7. Ice Harbor	1961	USACE	6	693	266	198	151
8. John Day	1968	USACE	16	2,480	1,328	977	762
9. Libby	1975	USACE	5	605	259	247	168
10. Little Goose	1970	USACE	6	930	278	188	151
11. Lower Granite	1975	USACE	6	930	279	186	134
12. Lower Monumental	1969	USACE	6	930	313	212	147
13. McNary	1953	USACE	14	1,120	665	556	456
14. The Dalles	1957	USACE	22	2,080	1,030	808	631
15. Total Regulated Hydro Projects *(sum lines 1 through 14)*			**169**	**21,426**	**10,319**	**7,934**	**6,320**
Independent Hydro Projects							
16. Anderson Ranch	1950	USBR	2	40	19.3	11.7	10.4
17. Big Cliff	1954	USACE	1	21	13.4	13.2	11.0
18. Black Canyon	1925	USBR	2	8.5	7.5	6.8	5.5
19. Boise Diversion	1908	USBR	3	2.5	1.5	1.2	1.0
20. Chandler	1956	USBR	2	12.2	8.4	6.8	5.3
21. Cougar	1964	USACE	2	28	16.2	16.7	15.6
22. Cowlitz Falls	1994	LCPD#1	2	70	27.8	30.4	24.2
23. Detroit	1953	USACE	2	115	43.0	47.6	33.5
24. Dexter	1955	USACE	1	17	11.4	10.1	9.5
25. Foster	1968	USACE	2	23	11.1	12.1	10.1
26. Green Peter	1967	USACE	2	92	30.7	37.6	24.7
27. Green Springs	1960	USBR	1	18	6.7	6.7	6.7
28. Hills Creek	1962	USACE	2	34	20.6	17.0	15.9
29. Lookout Point	1954	USACE	3	138	45.9	40.4	32.0
30. Lost Creek	1975	USACE	2	56	43.5	38.8	27.7
31. Minidoka	1909	USBR	4	28	38.7	29.2	24.7
32. Palisades	1957	USBR	4	177	96.9	87.4	73.1
33. Roza	1958	USBR	1	14	13.9	9.3	7.9
34. Total Independent Hydro Projects *(sum lines 16 through 33)*			**38**	**894**	**457**	**423**	**339**
Small Non-Federally Owned Hydro Projects							
35. Dworshak/Clearwater Small Hydro	2000	ID DWR	1	5.4	2.6	2.6	2.6
36. Rocky Brook	1985	MCPD#1	1	1.6	0.3	0.3	0.3
37. Total Non-Federally Owned Hydro Projects *(line 35 + line 36)*			**2**	**7**	**2.9**	**2.9**	**2.9**
38. Total Hydro Generation *(line 15 + line 34 + line 37)*			**209**	**22,327**	**10,778**	**8,360**	**6,662**

a/ Firm energy is the 12-month annual average for OY 2024 assuming 10th percentile (P10) water conditions
b/ Bonneville Dam generation totals include Bonneville Fishway
c/ High Energy = 90th percentile, Median Energy = 50th percentile, Firm Energy = 10th percentile
d/ Maximum Capacity represent full capacity of resource including overload.

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

Table 2-7

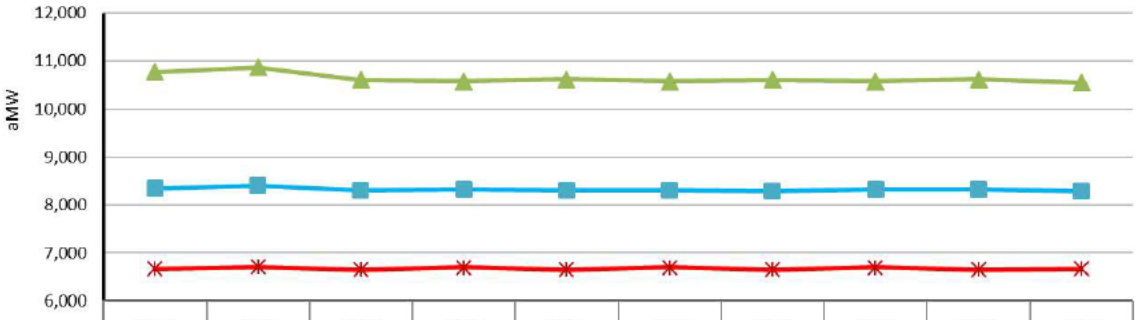
Federal System
Non-Hydro Project Generation and Contract Purchases
OY 2024

Project	Initial Service Date	Resource Type	Operator	Maximum Capacity [a/] (Peak MW)	Firm Energy (aMW)
Non-Hydro Resources					
1. Columbia Generating Station	1984	Nuclear	ENW	1,178	1,116
2. Condon Wind Project [b/]	2002	Wind	Condon Wind Project, LLC	0	0.0
3. Stateline Wind Project [c/]	2001	Wind	PPM, FLP	0	21.2
4. Klondike Phase III [d/]	2007	Wind	NW Wind Power	0	11.8
5. Fourmile Hill Geothermal [e/]	Not in Service	Geo.	Calpine	0	0
6. Total Federal System Non-Hydro Resources *(sum lines 1 through 5)*				**1,178**	**1,149**
Contract Purchases					
7. Canadian Entitlement for Canada (non-Federal)				235	134
8. Canadian Imports				1	1
9. Pacific Southwest Imports				0	0
10. Intra-Regional Transfers In (Pacific Northwest Purchases)				350	63
11. Slice Transmission Loss Return				41	29
12. Total Federal System Contract Purchases *(sum lines 7 through 11)*				**627**	**227**
13. Total Federal System Non-Hydro Resources and Contract Purchases *(line 6 + line 12)*				**1,805**	**1,376**

Federal System Hydro Generation Variability: The generating capability of Federal system hydroelectric projects depends on the amount of water flowing through the facilities, the physical capacity of the facilities, flow requirements pursuant to biological opinions, and other operating limitations. Table 2-8, next, shows the annual variability of hydro generation under three streamflow conditions.

Table 2-8

Federal System
Variability of Annual Hydro Generation
OY 2024 through 2033
Under Different Water Conditions

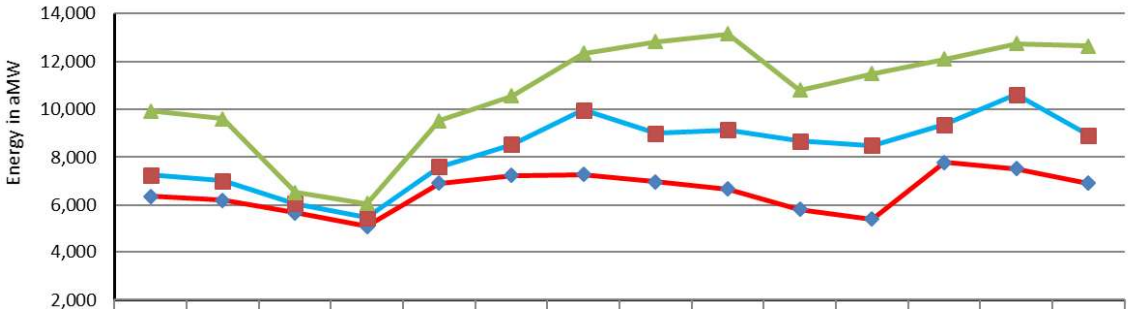


	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Firm Water (P10)	6,662	6,707	6,644	6,693	6,646	6,693	6,645	6,693	6,644	6,667
Median Water (P50)	8,360	8,403	8,308	8,328	8,307	8,316	8,285	8,323	8,334	8,300
High Water (P90)	10,778	10,866	10,607	10,582	10,614	10,582	10,608	10,582	10,613	10,550

In OY 2024, annual Federal system hydro energy generation is forecasted to be 6,662 aMW under Firm water conditions. However, under the high streamflow conditions these same Federal system hydro resources could generate 10,778 aMW. Table 2-8, above, shows the annual variability of Federal system hydro generation, and Table 2-9 shows the monthly variability of the Federal system hydro generation for OY 2024, under the same water conditions. Higher generation levels in the January through mid-April period are largely due to drafting reservoirs for power production and flood control, which can vary widely due to rainfall and snowpack levels in the Columbia River Basin. Power production from late-April through July is variable due to the timing and amount of the Columbia River Basin snowmelt runoff. Power production decreases through the end of the summer and early fall as streamflows are reduced due to depleted snowpack and lower precipitation levels. Annual water volume variability does not have a substantial impact on generation from the Federal system hydro resources in September and October. Hydro generation can vary by more than 6,000 aMW in a single month depending on project operations and the availability of water.

Table 2-9

Federal System
Variability of Monthly Hydro Generation
OY 2024 - Under Different Water Conditions

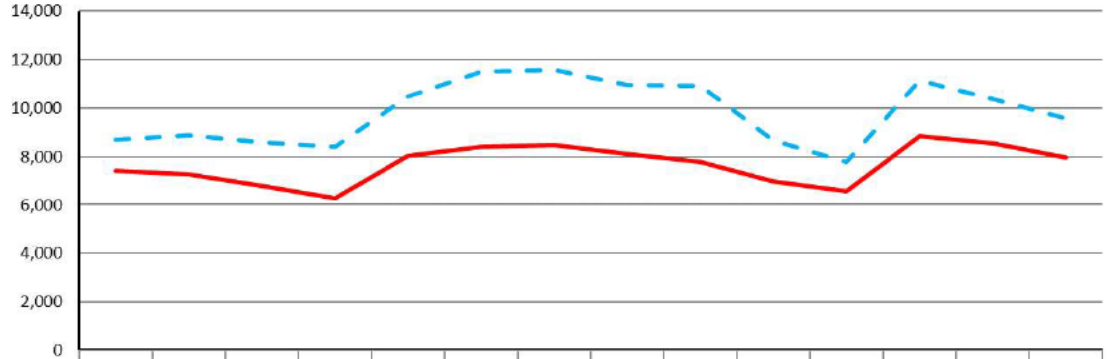


	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Firm Water (P10)	6,356	6,201	5,684	5,117	6,913	7,232	7,271	6,964	6,660	5,815	5,417	7,790	7,508	6,902
Median Water (P50)	7,251	7,008	6,052	5,472	7,600	8,535	9,960	8,991	9,144	8,677	8,492	9,353	10,608	8,910
High Water (P90)	9,938	9,597	6,521	6,069	9,515	10,565	12,340	12,833	13,149	10,796	11,494	12,086	12,741	12,646

Total Federal System Resources: Table 2-10, illustrates the monthly shape of the forecasted total Federal system generation for energy and 120-Hour capacity for OY 2024, under Firm water conditions. This includes generation from all Federal system hydro and non-hydro resources and Federal system contract purchases. The Federal system maintains similar monthly shapes over the study period, with the highest generation forecasted in mid-summer, early winter, and late spring periods.

Table 2-10

Federal System
OY2024 Monthly Generation
Energy and 120-Hour Capacity
Firm Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	7,418	7,280	6,798	6,274	8,060	8,405	8,463	8,129	7,800	6,976	6,584	8,833	8,553	7,970
120 Hour Cap (MW)	8,706	8,864	8,607	8,422	10,499	11,510	11,592	10,972	10,932	8,671	7,795	11,161	10,387	9,584

Key Results

Annual Energy: Table 2-11, shows that the Federal system is forecasted to have annual energy deficits throughout the study period. The individual components of the Federal system annual energy loads and resources are shown in Exhibit 4-1 for OY 2024 through 2033. The Federal system monthly energy loads and resources are shown in Exhibit 4-2 for OY 2024.

Table 2-11

Federal System
Annual Energy Surplus/Deficit
OY 2024 through 2033
Firm Water Conditions

Energy (aMW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Surplus/Deficit	-18	-289	-147	-223	-159	-303	-263	-357	-303	-424

Table 2-12 compares the 2023 White Book Federal system annual firm energy surplus/deficit results to those from the 2022 White Book. Comparing with the previous White Book, the 2023 White Book shows an increased deficit throughout the studying period except for the first year, with larger deficits in the end of the study period. These results reflect changes in both load obligations and Federal system generation.

Table 2-12

Federal System
Annual Energy Surplus/Deficit Comparison
OY 2024 through 2033
Firm Water Conditions

Energy (aMW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
2023 White Book P10 generation	-18	-289	-147	-223	-159	-303	-263	-357	-303	-424
2022 White Book 1937 Critical Water Conditions	-103	-245	-39	-118	-25	-164	-68	-204	-105	*n/a*
Difference ***(2023 WBK – 2022 WBK)***	86	-44	-107	-105	-134	-139	-195	-153	-198	*n/a*

120-Hour Capacity: Table 2-13 shows that the Federal system January 120-Hour capacity is mostly surplus under the firm water condition, except for the last operating year of the study period. The detailed components of the Federal system January 120-Hour capacity loads and resources for OY 2024 through 2033 are shown in Exhibit 4-3. The Federal system monthly 120-Hour capacity loads and resources are shown in Exhibit 4-4 for OY 2024.

Table 2-13

Federal System
January 120-Hour Capacity Surplus/Deficit
OY 2024 through 2033
Firm Water Conditions

January 120-Hour Capacity (MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Surplus/Deficit	414	199	467	69	98	53	66	10	15	-123

Table 2-14 compares the 2023 White Book January firm 120-Hour capacity surplus/deficit results to those from the 2022 White Book. This study shows a large difference in January 120-Hour capacity when compared with 2022 White Book in each of the forecast OY, majority due to change from critical 1937 to P10 firm water condition analysis which affecting hydro capacity. Details previously stated in the Hydro Resources Modeling section.

Table 2-14

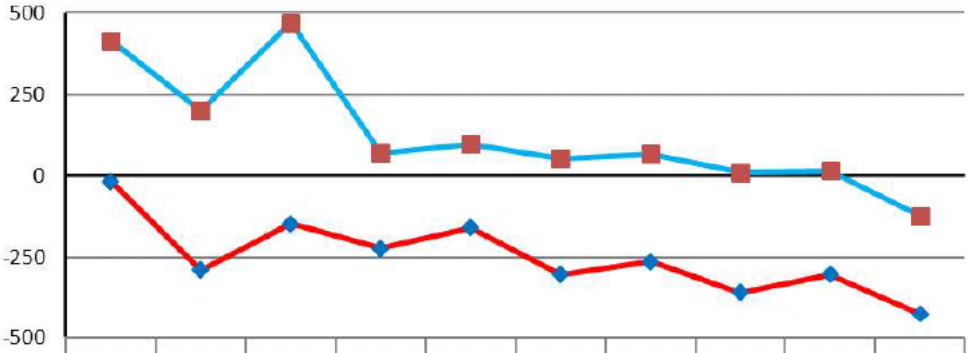
Federal System
January 120-Hour Capacity Surplus/Deficit Comparison
OY 2024 through 2033
Firm Water Conditions

January 120-Hour Capacity (MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
2023 White Book P10 generation	414	199	467	69	98	53	66	10	15	-123
2022 White Book 1937 Critical Water Conditions	-1,215	-1,312	-1,086	-1,263	-1,254	-1,099	-1,208	-1,163	-1,267	*n/a*
Difference *(2023 WBK – 2022 WBK)*	1629	1511	1554	1332	1351	1151	1274	1174	1282	*n/a*

Federal System Annual Surplus/Deficits: Table 2-15 graphically presents the annual firm energy and January 120-Hour capacity surplus/deficits. Over the study period, the Federal system is forecasted to have annual firm energy deficits as high as 424 aMW at the end of the study period. The January firm 120-Hour capacity forecasts show the Federal system surplus trend decreasing over the period, and eventually deficit at the last year of the study period at 123 MW. Variations in the annual energy deficits between the odd and even OYs are due to the biennial Columbia Generation Station (CGS) maintenance schedule.[7]

Table 2-15

Federal System
Annual Energy and January 120-Hour Capacity Surplus/Deficit
OY 2024 through 2033
Firm Water Conditions



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Energy (aMW)	-18	-289	-147	-223	-159	-303	-263	-357	-303	-424
January 120Hour Cap (MW)	414	199	467	69	98	53	66	10	15	-123

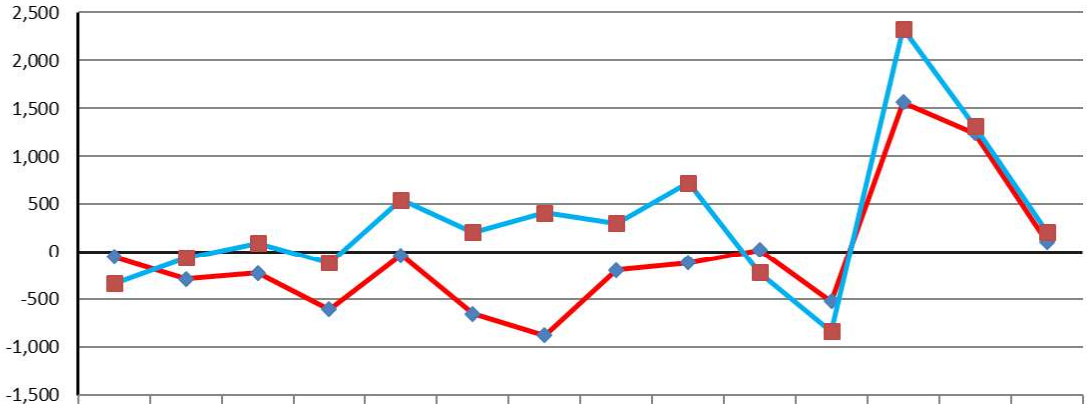
Federal System Monthly Surplus/Deficit: Table 2-16 graphically presents the Federal system monthly firm energy and 120-Hour capacity surpluses and deficits for OY 2024. Forecasts for energy and 120-Hour

[7] During even calendar years, CGS does not have scheduled maintenance and is forecast to produce 1,116 aMW annually. In odd calendar years, CGS has scheduled maintenance in May and June, and is forecasted to produce 994 aMW annually.

capacity maintain similar monthly shapes over the study period. This shows that for each month the Federal system energy and 120-Hour capacity surplus or deficit position changes during the year, with December, January, and the second half of April showing the largest monthly deficits in energy. May and June showing the largest surpluses.

Table 2-16

Federal System
Monthly Energy and 120-Hour Capacity Surplus/Deficit
OY 2024 Firm Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	-49	-284	-224	-603	-35	-652	-875	-192	-112	21	-522	1,566	1,239	108
120 Hour Cap (MW)	-333	-62	93	-113	548	209	414	302	727	-221	-836	2,332	1,315	213

Conclusion

Under Firm water conditions the Federal system shows annual firm energy deficits throughout the 2024-2033 study period. These annual energy deficits range from 18 aMW in OY 2024 to as high as 424 aMW in OY 2033. Under firm water conditions, the Federal system generally shows larger monthly energy deficits across the winter and early spring until spring runoff start, with surpluses through the spring runoff in May and across the early summer months.

The Federal system capacity analysis shows January 120-Hour capacity, under firm water condition, surplus until the last year of the study horizon on an annual basis. On a monthly basis, the study shows 120-Hour capacity largest deficits in April, caused by low water conditions in years where run-off hasn't began in until later, and surpluses though most of the year.

As water conditions improve, the Federal system surplus/deficit forecasts can vary greatly. For example, the annual energy surpluses can increase by more than 3,000 aMW under better water conditions, while the monthly surplus or deficit position can vary by more than 5,000 aMW (March). Similarly, Federal system 120-Hour capacity surpluses and deficits for OY 2024 can vary by more than 4,500 MW in the second part of April depending on water conditions.

Federal system monthly energy deficits are generally greater than the 120-Hour capacity deficits under firm water conditions. This result indicates that the Federal system is continues to be more energy constrained than capacity across the study period. The range of Federal system monthly surpluses and deficits forecasts under all 30-historical water conditions is presented in Exhibit 4-5. Additional monthly and annual details for OY 2024 through 2033 are available upon request, and a detailed list of available data is included in Appendix A.

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Section 3: Pacific Northwest Regional Analysis

The PNW Regional Analysis is an OY analysis that provides Bonneville's deterministic forecast of the PNW region's loads and resources over a 10-year period from OY 2024 through 2033. Firm load and resource forecasts are made for both energy and 120-Hour capacity based on regional retail loads, contract obligations, and resources. This White Book analysis assumes that generation from all regional uncommitted Independent Power Producer (IPP) projects is available to meet regional load. Regional retail loads, contract sales and purchases, and generating resource forecasts incorporate annual regional utility data submittals received by Bonneville.

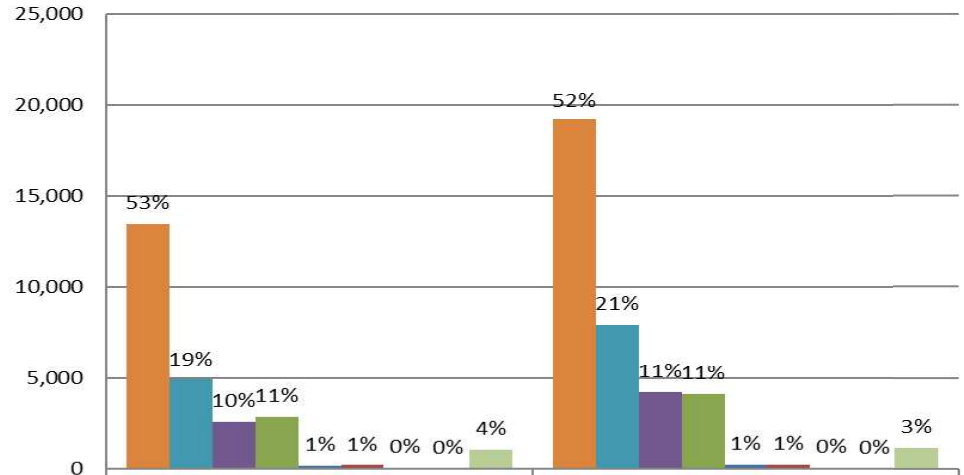
Regional Loads

The regional analysis incorporates regional load projections, which consist of two separate components: 1) Total Retail Loads (TRL), which is the sum of individual utilities' retail power consumption within the PNW region; and 2) Regional contract sales (Exports), which are the sum of all reported long-term regional contract deliveries to entities outside the PNW region. The TRL forecasts for the regional analysis are developed by Bonneville's ALF system. TRL forecasts reflect normal weather conditions, include historic conservation savings, and do not include specific adjustments for future climate change impacts. With the exception of power commitments under the Treaty, all Export contract deliveries follow individual contract terms and are not assumed to be renewed after their expiration. Treaty power deliveries are assumed to be in place through the study period. The sum of the forecasted TRL and Export contracts represent the regional loads for the PNW. Regional loads are comprised of about 96 percent retail loads and 4 percent exports.

Table 3-1 shows the forecasted composition of PNW regional load for OY 2024. For the PNW region.

Table 3-1

PNW Region
Firm Regional Loads by Customer Class
OY 2024



	Energy (aMW)	January 120-Hour Capacity (MW)
Investor-Owned Utility	13,455	19,202
Public Utility District	4,901	7,940
Municipality	2,562	4,226
Cooperative	2,854	4,113
Federal Agency	148	232
USBR	188	201
DSI 1/	53	65
Marketer	3	3
Exports	1,019	1,143

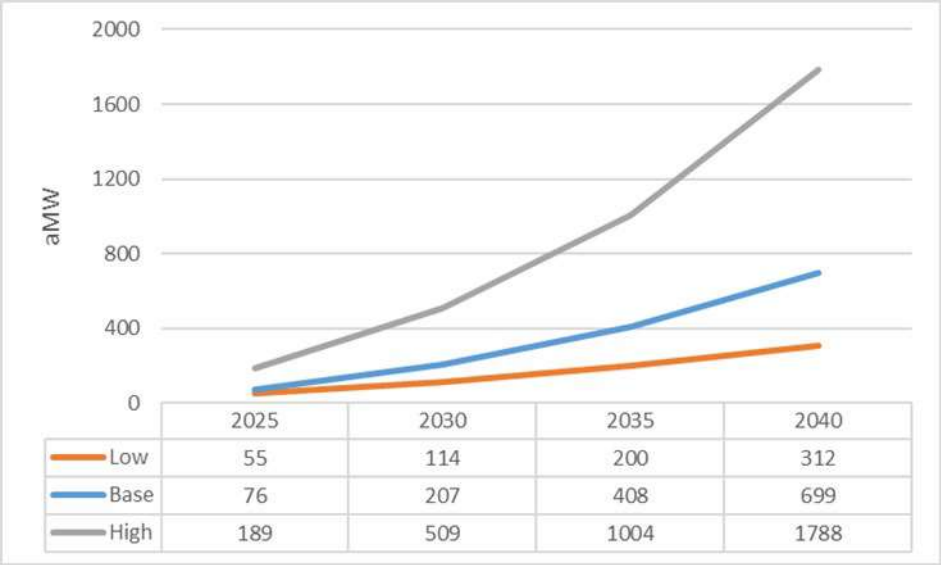
[1] Direct-Service Industry (DSI) loads include regional loads currently served by Bonneville through DSI service contracts and former DSIs served by other energy suppliers.

Electrification in Regional Loads

The regional load forecast includes some electrification, however the growing interest in electrification signals a potential for significant load growth in the future. Table 3-2, a re-print from the 2022 White Book, presents Bonneville's view of the wide possible range of electrification load increases to regional loads. While this study includes the base forecasted load increases from the table related to electrification, the table shows the range of possible load increase from electrification, with possible electrification load increases on a scale of 2.5 times the base forecast in 2030. Load increases due to electrification are expected to result from electrical vehicle use and the increasing conversion to electric applications to reduce greenhouse gases.

Table 3-2

PNW Region
Annual Energy – Electrification Load Obligation Increases
(Re-print from 2022 White Book)



	2025	2030	2035	2040
Low	55	114	200	312
Base	76	207	408	699
High	189	509	1004	1788

Regional Resources

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

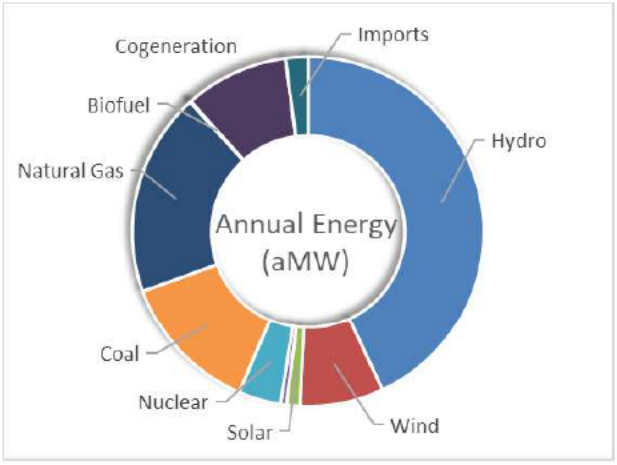
Table 3-3, next, summarizes the resource generation available to meet PNW regional loads. The generation forecasts for these resources are provided by Bonneville models or the project owners. New regional generating projects are included when those resources begin operating or are under construction and have a scheduled on-line date; similarly, retiring resources are removed from the forecasts based on the date of the announced retirement. Regional resource forecasts assume the retirement of the following coal projects over the study period: Centralia 2 (December 1, 2025) and Valmy 2 (January 1, 2026). Contract purchases are provided by the individual utility, follow specific contract provisions, and can have various delivery arrangements.

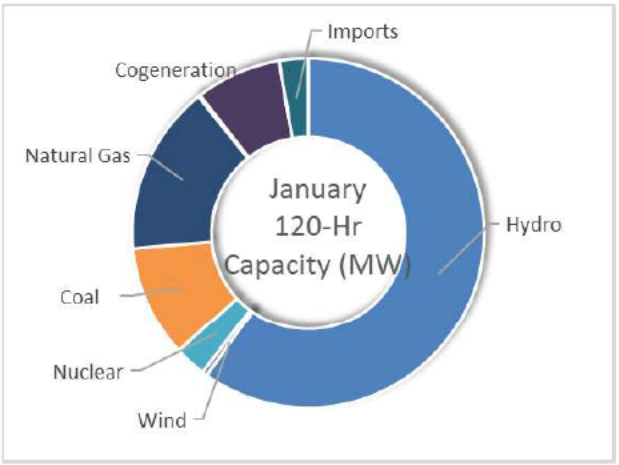
Table 3-3 [a/]

PNW Region
Generation by Resource Type
OY 2024 Firm Water Conditions

Project Type	Annual Energy (aMW)	Percent of Energy	January 120-Hour Capacity (MW)	Percent of Capacity
Hydro	12,081	43%	24,046	60%
Wind	2,200	8%	0	0%
Solar	352	1.2%	0	0%
Other Renewable	159	0.6%	182	0.5%
Nuclear	1,116	4%	1,178	3%
Coal	3,751	13%	4,195	10%
Natural Gas	5,373	19%	6,288	16%
Petroleum	0	0%	39	0.1%
Biofuel	26	0.1%	31	0.1%
Cogeneration	2,737	10%	3,179	8%
Imports	588	2%	1,065	3%
Total Regional Resources	**28,382**	**100%**	**40,202**	**100%**

[a/] Any discrepancies in totals for figures portrayed in this table are due to rounding.





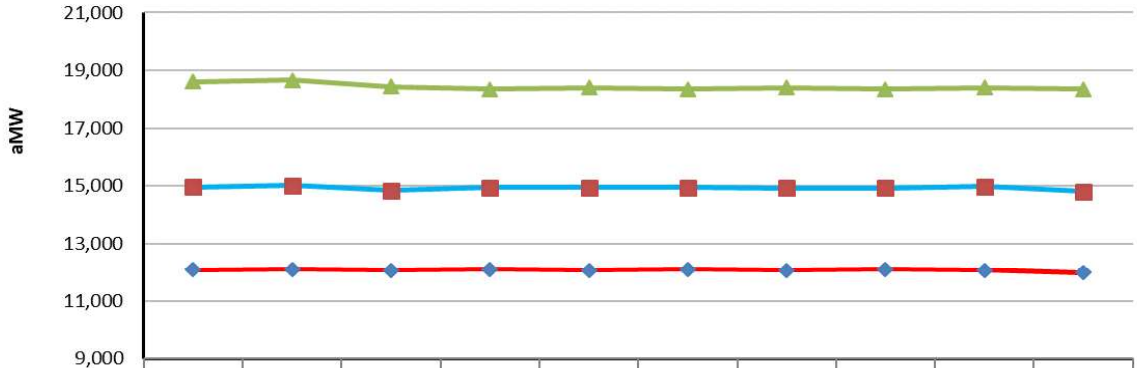
Regional Hydro Generation Variability: The generating capability of regional hydroelectric projects depends upon the amount of water flowing through the facilities, the physical capacity of the facilities, flow requirements pursuant to non-power requirements, and other operating limitations. Similarly to the federal hydro resources, Bonneville utilizes the 30-year streamflow record and percentile of T1SFCO results for planning purposes. To simplify the presentation of hydro generation variability, this study uses three water conditions to represent the magnitude of hydro generation variability.

Table 3-4 shows the annual variability of the region's hydro generation under the three generation scenarios, details please refer to Hydro Resources Modeling section.

In OY 2024, annual Firm energy generation from regional hydro projects is forecasted to be 12,081 aMW under the firm water condition. This represents about 43 percent of region's resources. However, the generating potential from regional hydro projects can vary annually by over 6,000 aMW depending on water conditions.

Table 3-4

PNW Region
Variability of Annual Hydro Generation
OY 2024 through 2033
Under Different Water Conditions

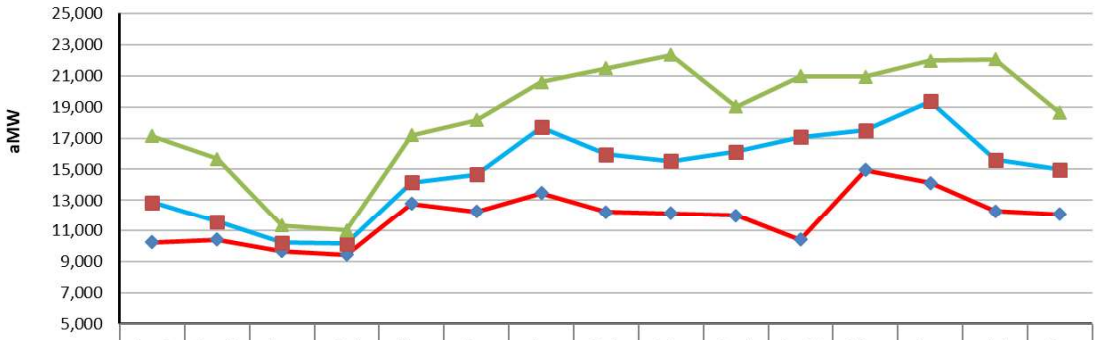


	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Firm Water (P10)	12,081	12,110	12,061	12,099	12,062	12,099	12,062	12,099	12,061	11,981
Median Water (P50)	14,970	15,020	14,845	14,952	14,942	14,944	14,936	14,928	14,991	14,816
High Water (P90)	18,617	18,662	18,442	18,356	18,408	18,356	18,400	18,356	18,407	18,356

Table 3-5 shows the monthly variability of regional hydro generation under the same three water conditions for OY2024. High generation levels in the January through March period is largely due to drafting reservoirs for power production and flood control, which can vary widely due to rainfall and snowpack levels in the Columbia River Basin. Power production in late-April through July is variable due to the timing and amount of Columbia River Basin snowmelt runoff. Power production decreases through the end of the summer and early fall as streamflows are reduced due to depleted snowpack and lower precipitation levels. Water variability does not have a substantial impact on regional hydro generation from August through November. Regional hydro generation capability can vary by as much as 10,000 aMW in a month, depending on the availability of water.

Table 3-5

PNW Region
Variability of Monthly Hydro Generation
OY 2024 under Different Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
Firm Water (P10)	10,268	10,424	9,680	9,468	12,772	12,264	13,459	12,220	12,157	12,010	10,436	14,953	14,121	12,294	12,081
Median Water (P50)	12,868	11,591	10,237	10,180	14,150	14,681	17,712	15,952	15,523	16,130	17,067	17,499	19,372	15,600	14,970
High Water (P90)	17,128	15,680	11,353	11,036	17,178	18,161	20,582	21,478	22,334	19,026	20,956	20,936	21,970	22,056	18,617

Variability Due to IPP Generation Delivered to the PNW Region: The PNW regional study includes uncommitted PNW IPP generation as regional resources. These resources, or the share of these resources, that are not committed to serving specific loads represent approximately 2,790 aMW of energy with an associated 3,172 MW of January 120-Hour capacity in OY 2024. The inclusion of this uncommitted IPP generation is reasonable from a long-term planning perspective because the PNW Regional Analysis does not include any reliance on market purchases. However, PNW utilities may have to compete with other western markets to secure this generation to meet electricity demand. Table 3-6, below, details the region's total uncommitted IPP annual energy and January 120-Hour capacity generation forecasts over the OY 2024 through 2033 study period. Table 3-7 details the region's uncommitted IPP projects and the associated fuel types. If uncommitted IPP generation is secured for long-term periods by load serving entities within the region or outside the region, the IPP forecasts will be updated in future studies to reflect these changes.

Table 3-6

PNW Region
Uncommitted Independent Power Producer Generation
Annual Energy and January 120-Hour Capacity
OY 2024 through 2033

Regional Uncommitted IPP	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Annual Energy (aMW)	2,790	2,796	2,622	2,552	2,581	2,592	2,587	2,591	2,586	2,596
January 120-Hour Capacity (MW)	3,172	3,172	2,881	2,881	2,881	2,881	2,881	2,881	2,881	2,881

Table 3-7

PNW Region
Uncommitted Independent Power Producer Projects
OY 2024 Firm Water Condition

Project	Fuel Type	Energy (aMW)	Peak (MW)
Airport Solar	Solar	13	0
Centralia Complex [a/b/]	Coal	260	290
Condon Wind	Wind	12	0
Cosmopolis Specialty Fibres	Wood Waste	14	14
Hermiston Power Project	Wood Waste	567	630
International Paper Energy Center	Wood Waste	17	22
Juniper Canyon Wind	Wind	36	0
Kittitas Valley Wind	Wind	24	0
Klamath Generation Facility	Natural Gas	436	484
Klamath Generation Peakings (CT)	Natural Gas	90	100
Klondike Wind 1	Wind	6	0
Klondike Wind 3	Wind	23	0
Klondike Wind 3a	Wind	18	0
Leaning Juniper Wind	Wind	47	0
Longview Fibre Paper & Packaging	Wood Waste	35	35
Nippon Paper Cogen (Port Angeles)	Wood Waste	0	0
Pelton	Hydro	14	41
Priest Rapids	Hydro	85	154
Rock Island	Hydro	169	154
Rocky Reach	Hydro	157	339
Round Butte	Hydro	30	99
Satsop Combustion Turbine Project	Natural Gas	584	650
SDS Lumber	Wood Waste	1	1
Smith Creek (Idaho)	Hydro	7	0
Stateline Wind	Wind	8	0
Tacoma Biomass (WestRock)	Wood Waste	44	55
Tieton Dam (Yakima)	Hydro	0	0
Vansycle Wind	Wind	23	0
Wanapum	Hydro	25	60
Weyerhaeuser Longview	Wood Waste	35	44
Willow Creek Wind	Wind	16	0
Total Uncommitted IPP Generation		2,796	3,172

[a/] Centralia #1 (670 MW) retired Dec 1, 2020
[b/] Centralia #2 (670 MW) is scheduled for retirement on Dec 1, 2025

Key Results

Annual Energy: Table 3-8 shows annual energy surpluses for the PNW region throughout the study period under Firm water conditions. This study assumes that 100 percent of the PNW region's uncommitted IPP generation (2,316 aMW in OY 2024) is available to serve regional loads. The individual components of the PNW regional annual energy loads and resources for OY 2024 through 2033 are shown in Exhibit 5-1. OY2024 Monthly PNW regional energy loads and details are shown in Exhibit 5-2. Further details of each component for OY 2024 through 2033 are available upon request.

Table 3-8

PNW Region
Annual Energy Surplus/Deficit
Assuming 100% of Uncommitted IPP Generation is Available to the Region
OY 2024 through 2033
Firm Water Conditions

Energy (aMW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Surplus/Deficit	2,316	1,905	1,357	932	728	509	553	40	144	-61

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

Table 3-9

PNW Region
Variability of Annual Energy Surplus/Deficit
Assuming Different Levels of Uncommitted IPP Generation
OY 2024 through 2033
Firm Water Conditions

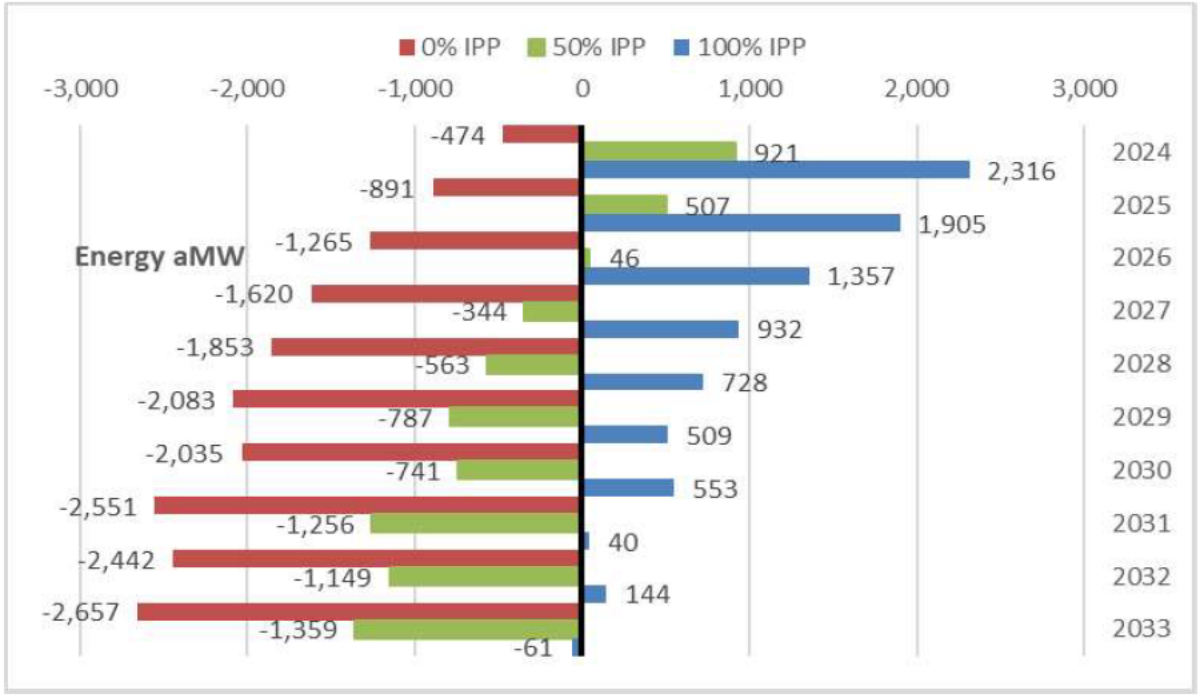


Table 3-10 compares the 2023 White Book PNW regional annual firm energy surplus or deficit forecasts to the 2022 White Book results. The PNW region continues to have annual energy surpluses throughout most of the study period. Comparing to the 2022 White Book, the difference is mainly driven by increased regional resources such as several wind projects coming on-line and hydro generations increase due to change of Firm water conditions.

Table 3-10

PNW Region
Annual Energy Surplus/Deficit Comparison
Assuming 100% of Uncommitted IPP Generation is Available to the Region
OY 2024 through 2033
Firm Water Conditions

Energy (aMW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
2023 White Book P10 generation	2,316	1,905	1,357	932	728	509	553	40	144	-61
2022 White Book 1937 Critical Water Conditions	2277	1810	1180	646	394	43	47	-543	-440	n/a
Difference ***(2023 WBK – 2022 WBK)***	*38*	*96*	*176*	*286*	*334*	*466*	*506*	*583*	*584*	*n/a*

January 120-Hour Capacity: Table 3-11 shows the January firm 120-Hour capacity surpluses and deficits for the PNW region. The region is forecasted to have January 120-Hour capacity deficits over most of the study period. This assumes that 100 percent of PNW uncommitted IPP generation is available to serve regional loads. The individual components of the PNW regional January 120-Hour capacity loads and resources for OY 2024 through 2033 are shown in Exhibit 5-3, and OY2024 monthly PNW regional 120-Hour capacity loads and resources are in Exhibit 5-4.

Table 3-11

PNW Region
January 120-Hour Capacity Surplus/Deficit
Assuming 100% of Uncommitted IPP Generation is Available to the Region
OY 2024 through 2033
Firm Water Conditions

January 120-Hour Capacity (MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Surplus/Deficit	449	155	-794	-1,438	-1,351	-1,940	-1,745	-3,254	-2,971	-3,506

Table 3-12 shows the significant variability in PNW regional January firm 120-Hour capacity surplus/deficit forecasts depending on the level of uncommitted IPP generation available to the region. IPP generation is detailed in Tables 3-6 and 3-7.

Table 3-12

PNW Region
Variability of January 120-Hour Capacity Surplus/Deficit
Assuming Different Levels of Uncommitted IPP Generation
OY 2024 through 2033 Firm Water Conditions

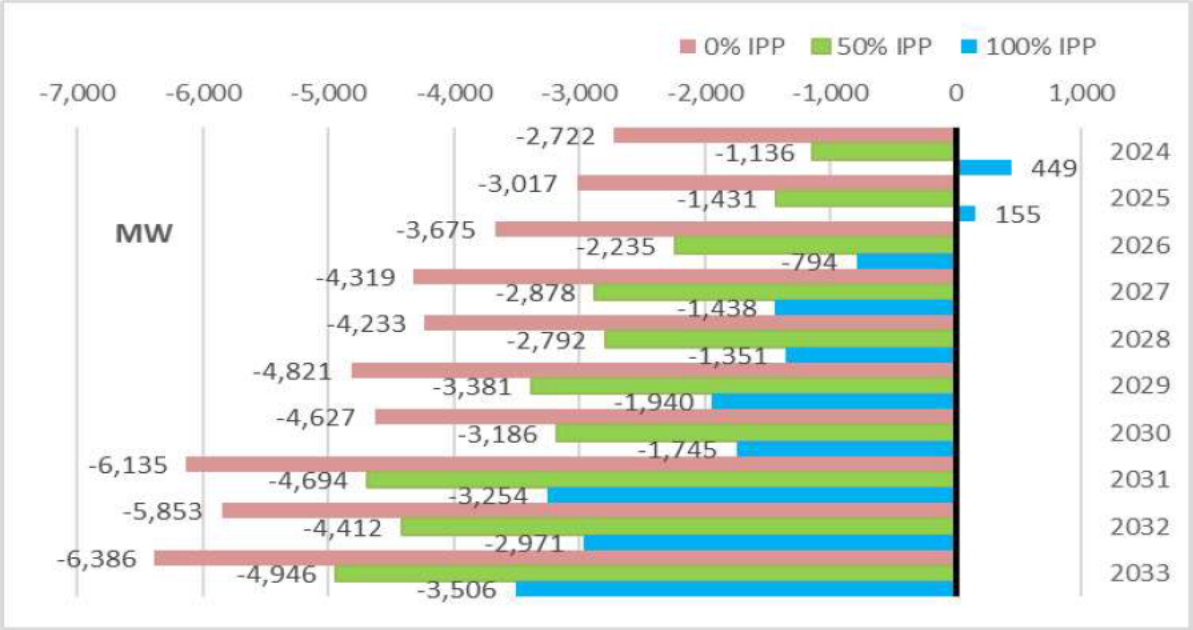


Table 3-13 compares the 2023 White Book January firm 120-Hour capacity forecast to the 2022 White Book results. Regional January 120-Hour capacity surplus/deficits show smaller deficits over the study period. The difference in January 120-Hour capacity deficits, compared to the 2022 White Book, are mainly driven by change from critical 1937 to P10 firm water condition analysis which resulted in increased hydro capacity output. Details stated in Hydro Resources Modeling section.

Table 3-13

PNW Region
January 120-Hour Capacity Surplus/Deficit Comparison
Assuming 100% of Uncommitted IPP Generation is Available to the Region
OY 2024 through 2033
Firm Water Conditions

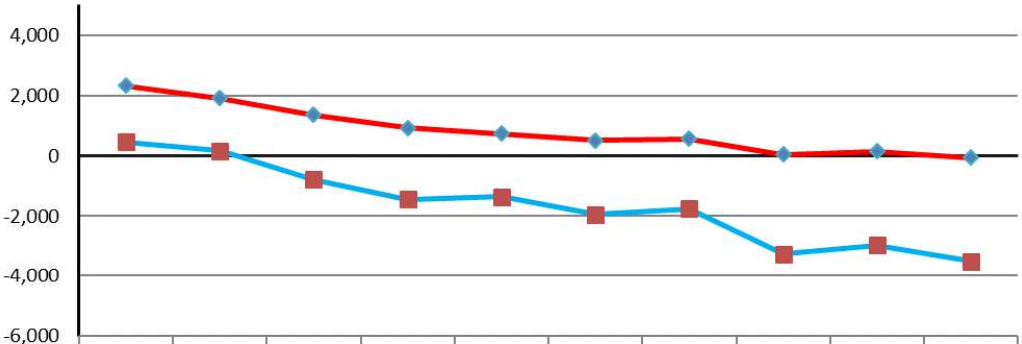
January 120-Hour Capacity (MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
2023 White Book P10 generation	449	155	-794	-1438	-1351	-1940	-1745	-3254	-2971	-3506
2022 White Book 1937 Critical Water Conditions	-767	-1,069	-2,173	-2,524	-2,846	-2,936	-3,298	-4,300	-4,506	n/a
Difference *(2023 WBK – 2022 WBK)*	1217	1224	1379	1086	1495	996	1553	1046	1535	n/a

Regional Annual Surplus/Deficit: Table 3-14 graphically presents the annual firm energy and January 120-Hour capacity surplus and deficit forecasts for the PNW Region. These forecasts assume 100 percent availability of the PNW's uncommitted IPP generation to serve regional loads. The regional annual energy and January 120-Hour capacity surplus and deficit declines over the 10-year study period. By the end of the period, the study

shows an annual energy deficit of 61 aMW, while January 120-Hour capacity is deficit over most of the study period ending with a deficit of 3,506 MW. Continuing declines in the surplus and deficit position over the study period, for both annual energy and January 120-Hour capacity, are driven by a combination of annual load growth, and the reduction of resources across the region.

Table 3-14

PNW Region
Annual Energy and January 120-Hour Capacity Surplus/Deficit
OY 2024 through 2033
Firm Water Conditions

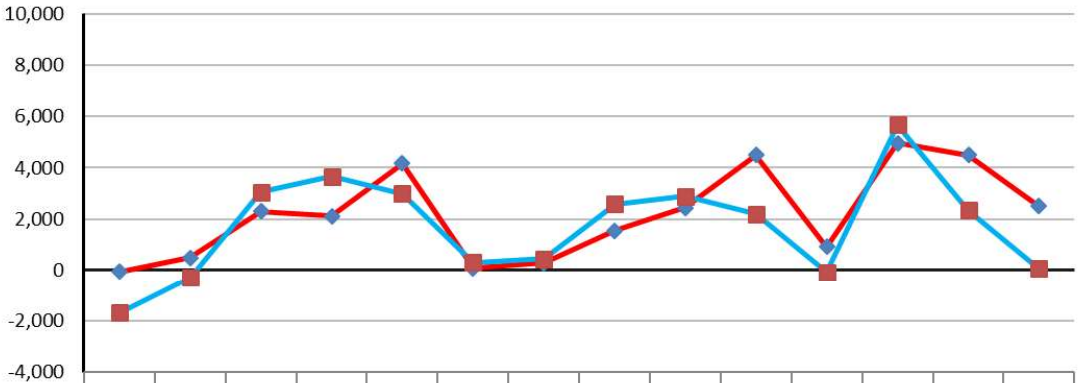


	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Energy (aMW)	2,316	1,905	1,357	932	728	509	553	40	144	-61
January 120 Hour Cap (MW)	449	155	-794	-1,438	-1,351	-1,940	-1,745	-3,254	-2,971	-3,506

Regional Monthly Surplus/Deficit: Table 3-15 graphically presents the monthly energy and 120-Hour capacity surplus or deficit forecasts for OY 2024. These forecasts assume 100 percent availability of the PNW's uncommitted IPP generation to serve regional loads. This monthly view shows the variability that the region experiences during the year, with December and January showing a deficit and the late spring showing the largest surpluses. Forecasts for monthly energy and 120-Hour capacity maintain similar shaping over the study period.

Table 3-15

PNW Region
Monthly Energy and 120-Hour Capacity Surplus/Deficit
OY 2024 Firm Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	-66	494	2,310	2,113	4,179	83	297	1,543	2,444	4,503	924	4,966	4,507	2,502
120-Hour Cap (MW)	-1,683	-300	3,053	3,666	2,995	304	449	2,587	2,886	2,205	-66	5,672	2,346	70

Conclusion

The PNW region is projected to have annual firm energy surpluses throughout most of the study period and a slight deficit in the last year, assuming modest load growth and 100 percent of the PNW region's uncommitted IPP generation is available to the region. However, using the same assumptions, the PNW region is forecast to be deficit in January firm 120-Hour capacity through most of the latter study periods, with surplus in the first two years. This study further shows that the PNW region is firm 120-Hour capacity constrained on a monthly basis. Since this analysis assumes that PNW uncommitted IPP generation is used to serve PNW regional load, the supply of power within the region can change dramatically if uncommitted IPP generation is committed to serve loads outside the PNW, or if committed resources retire early or unexpectedly. The surplus and deficit forecasts for all 30-historical water conditions are presented in Exhibit 5-5. Additional monthly and annual details for OY 2024 through 2033 are available upon request, and a detailed list can be found in Appendix A.

The regional energy and capacity deficits identified in this analysis may be mitigated through resource options discussed in the NWPCC's 2021 Northwest Power Plan. Bonneville provides this PNW regional planning analysis for informational purposes only.

Section 4: Federal System Analysis Exhibits

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Federal System Analysis Surplus Deficit
Operating Year 2024 to 2033
Firm Water Condition

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Loads and Resources - Federal System
Operating Year: 2024-2033 Water Year: P10
2023 White Book - 30WY Report Date: **12/5/2022**
S241-WB-20230315-141333

	Energy-aMW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	Firm Obligations										
1	**Load Following**	3917	4074	4117	4161	4166	4237	4264	4286	4300	4328
2	Preference Customers	3591	3738	3775	3816	3820	3887	3913	3935	3949	3976
3	Federal Agencies	138	148	154	157	159	162	162	163	163	164
4	USBR	188	188	188	188	188	188	188	188	188	188
5	Federal Diversity	0	0	0	0	0	0	0	0	0	0
6	**Tier 1 Block**	530	531	533	535	536	538	542	547	549	549
7	Tier 1 Block	530	531	533	535	536	538	542	547	549	549
8	**Slice**	2637	2672	2661	2644	2639	2633	2635	2628	2629	2623
9	Slice Block	1236	1259	1250	1259	1242	1250	1238	1245	1232	1245
10	Slice Output from T1 System	1400	1413	1411	1385	1397	1383	1397	1383	1397	1378
11	**Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
12	Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
13	**Contract Deliveries**	708	707	594	491	480	480	480	479	479	479
14	Exports	465	468	471	468	469	469	469	469	469	469
15	Intra-Regional Transfers (Out)	243	239	123	22	11	11	11	9	9	9
16	**Total Firm Obligations**	**7803**	**7996**	**7915**	**7841**	**7833**	**7899**	**7931**	**7952**	**7969**	**7990**
	Net Resources										
17	**Hydro**	6662	6707	6644	6693	6646	6693	6645	6693	6644	6667
18	Regulated Hydro - Net	6320	6358	6304	6343	6306	6343	6305	6343	6306	6365
19	Independent Hydro - Net	339	345	337	347	337	347	337	347	335	299
20	Small Hydro - Net	2.88	2.88	2.88	2.88	2.88	2.88	2.88	2.88	2.87	2.88
21	**Non-Hydro Renewable**	33.0	33.0	33.0	19.8	1.9	0.0	0.0	0.0	0.0	0.0
22	Wind - Net	33.0	33.0	33.0	19.8	1.9	0.0	0.0	0.0	0.0	0.0
23	Solar - Net	0	0	0	0	0	0	0	0	0	0
24	Other - Net	0	0	0	0	0	0	0	0	0	0
25	**Thermal**	1116	994	1116	994	1116	994	1116	994	1116	994
26	Nuclear - Net	1116	994	1116	994	1116	994	1116	994	1116	994
27	Coal - Net	0	0	0	0	0	0	0	0	0	0
28	Natural Gas - Net	0	0	0	0	0	0	0	0	0	0
29	Petroleum - Net	0	0	0	0	0	0	0	0	0	0
30	Biofuel - Net	0	0	0	0	0	0	0	0	0	0
31	Cogeneration - Net	0	0	0	0	0	0	0	0	0	0
32	**Contract Purchases**	227	227	228	165	165	165	165	165	165	164
33	Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
34	Intra-Regional Transfers (In)	63.1	63.0	63.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Non-Federal CER	134	134	135	135	135	135	135	135	135	135
36	Slice Transmission Loss Return	28.5	28.7	28.7	28.3	28.6	28.3	28.6	28.3	28.6	28.2
37	**Reserves & Losses**	-253	-253	-253	-253	-255	-256	-257	-257	-259	-258
38	Operating Reserves	0	0	0	0	0	0	0	0	0	0
39	Balancing Reserves	0	0	0	0	0	0	0	0	0	0
40	Transmission Losses	-253	-253	-253	-253	-255	-256	-257	-257	-259	-258
41	**Total Net Resources**	**7785**	**7707**	**7769**	**7619**	**7674**	**7596**	**7669**	**7594**	**7666**	**7566**
42	**Total Surplus/Deficit**	**-18**	**-289**	**-147**	**-223**	**-159**	**-303**	**-263**	**-357**	**-303**	**-424**

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Federal System Analysis Surplus Deficit
Operating Year 2024
Firm Water Condition

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Loads and Resources - Federal System
Operating Year: 2024 Water Year: P10
2023 White Book - 30WY (2001/P10) Report Date: **12/5/2022**

S241-WB-20230315-141333

2024	360	384	720	744	720	744	744	696	744	360	360	744	720	744	8784
Energy-aMW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
Firm Obligations															
1 **Load Following**	3900	3902	3415	3431	3736	4493	4498	4136	3787	3695	3695	3695	3972	4236	3917
2 Preference Customers	3454	3456	3025	3180	3578	4313	4322	3945	3576	3330	3330	3230	3457	3674	3591
3 Federal Agencies	116	117	104	129	149	169	167	172	150	131	131	120	120	135	138
4 USBR	330	329	286	123	9.67	10.8	8.39	18.0	61.0	234	234	345	395	427	188
5 Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 **Tier 1 Block**	342	342	562	488	808	808	891	810	793	386	386	139	21.3	316	530
7 Tier 1 Block	342	342	562	488	808	808	891	810	793	386	386	139	21.3	316	530
8 **Slice**	2439	2448	2317	2256	2844	3050	3243	2668	2629	2170	2321	2730	2619	2579	2637
9 Slice Block	1133	1133	1116	1136	1322	1510	1494	1331	1276	1178	1178	1133	1084	1120	1236
10 Slice Output from T1 System	1306	1315	1201	1120	1522	1540	1749	1337	1353	992	1143	1597	1535	1459	1400
11 **Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11 0	11.0	11.0	11.0	11.0	11.0	11.0
12 Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
13 **Contract Deliveries**	775	861	717	692	695	694	696	697	692	693	693	692	692	720	708
14 Exports	512	598	454	454	454	454	454	454	454	454	454	454	454	483	465
15 Intra-Regional Transfers (Out)	263	264	262	237	241	240	241	242	237	238	238	237	237	237	243
16 **Total Firm Obligations**	**7467**	**7564**	**7022**	**6877**	**8095**	**9057**	**9338**	**8321**	**7912**	**6955**	**7106**	**7267**	**7314**	**7862**	**7803**
Net Resources															
17 **Hydro**	6356	6201	5684	5117	6913	7232	7271	6964	6660	5815	5417	7790	7508	6902	6662
18 Regulated Hydro - Net	6051	5800	5447	4842	6478	6921	6852	6747	6404	5528	5030	7407	7050	6488	6320
19 Independent Hydro - Net	303	398	234	273	433	307	416	213	252	283	383	380	455	412	339
20 Small Hydro - Net	2.63	2.63	2.63	2.67	2.84	3.19	3.21	3.04	3.10	3.09	3.09	2.83	2.72	2.63	2.88
21 **Non-Hydro Renewable**	22.6	33.8	31.5	25.3	36.2	27.6	14.8	24.4	28.1	50.2	42.3	45.2	44.7	43.7	33.0
22 Wind - Net	22.6	33.8	31.5	25.3	36.2	27.6	14.8	24.4	28.1	50.2	42.3	45.2	44.7	43.7	33.0
23 Solar - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24 Other - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25 **Thermal**	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116
26 Nuclear - Net	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116
27 Coal - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28 Natural Gas - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29 Petroleum - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30 Biofuel - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31 Cogeneration - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32 **Contract Purchases**	167	168	185	218	255	300	335	287	248	220	223	168	167	170	227
33 Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1 00	1.00	1.00	1.00	1.00	1.00	1.00
34 Intra-Regional Transfers (In)	0	0	25.0	64.0	88.9	138	164	125	89.0	64.4	64.4	0	0	0	63.1
35 Non-Federal CER	136	137	136	131	136	131	136	135	132	136	136	136	131	136	134
36 Slice Transmission Loss Return	30.0	30.2	23.3	21.7	29.6	29.9	33.9	26.0	26.3	19.3	22.2	31.0	35.3	33.5	28.5
37 **Reserves & Losses**	-244	-239	-219	-203	-260	-271	-273	-262	-252	-225	-214	-286	-282	-262	-253
38 Operating Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39 Balancing Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40 Transmission Losses	-244	-239	-219	-203	-260	-271	-273	-262	-252	-225	-214	-286	-282	-262	-253
41 **Total Net Resources**	**7418**	**7280**	**6798**	**6274**	**8060**	**8405**	**8463**	**8129**	**7800**	**6976**	**6584**	**8833**	**8553**	**7970**	**7785**
42 **Total Surplus/Deficit**	**-49**	**-284**	**-224**	**-603**	**-35**	**-652**	**-875**	**-192**	**-112**	**21**	**-522**	**1,566**	**1,239**	**108**	**-18**

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Federal System Analysis Surplus Deficit
Operating Year 2024 to 2033
Firm Water Condition

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Loads and Resources - Federal System
Operating Year: 2024-2033 Water Year: P10 January
2023 White Book - 30WY Report Date: **12/5/2022**

S241-WB-20230315-141333

	120Hr-MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	Firm Obligations	2002	2002	2002	2001	2002	2001	2002	2001	2002	2001
1	**Load Following**	5151	5325	5346	5417	5419	5465	5479	5494	5517	5571
2	Preference Customers	6182	6354	6372	6443	6442	6525	6534	6542	6572	6602
3	Federal Agencies	224	233	238	240	244	248	248	249	249	250
4	USBR	201	201	201	201	201	201	201	201	201	201
5	Federal Diversity	-1456	-1462	-1465	-1467	-1468	-1509	-1504	-1498	-1505	-1482
6	**Tier 1 Block**	952	946	951	989	995	958	967	976	982	1015
7	Tier 1 Block	952	946	951	989	995	958	967	976	982	1015
8	**Slice**	3606	3637	3631	3644	3626	3632	3617	3628	3616	3626
9	Slice Block	1494	1525	1505	1522	1500	1511	1491	1505	1489	1506
10	Slice Output from T1 System	2112	2112	2126	2121	2126	2121	2126	2123	2127	2120
11	**Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
12	Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
13	**Contract Deliveries**	1458	1458	1258	1158	1158	1158	1158	1151	1151	1151
14	Exports	1142	1142	1142	1142	1142	1142	1142	1142	1142	1142
15	Intra-Regional Transfers (Out)	316	316	116	16.4	16.4	16.4	16.4	9.44	9.44	9.44
16	**Total Firm Obligations**	**11178**	**11376**	**11197**	**11219**	**11209**	**11224**	**11232**	**11260**	**11277**	**11374**
	Net Resources										
17	**Hydro**	11828	11828	11899	11876	11899	11876	11899	11876	11899	11861
18	Regulated Hydro - Net	11287	11287	11358	11602	11358	11602	11358	11602	11358	11602
19	Independent Hydro - Net	536	536	536	269	536	269	536	269	536	254
20	Small Hydro - Net	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59
21	**Non-Hydro Renewable**	0	0	0	0	0	0	0	0	0	0
22	Wind - Net	0	0	0	0	0	0	0	0	0	0
23	Solar - Net	0	0	0	0	0	0	0	0	0	0
24	Other - Net	0	0	0	0	0	0	0	0	0	0
25	**Thermal**	1178	1178	1178	1178	1178	1178	1178	1178	1178	1178
26	Nuclear - Net	1178	1178	1178	1178	1178	1178	1178	1178	1178	1178
27	Coal - Net	0	0	0	0	0	0	0	0	0	0
28	Natural Gas - Net	0	0	0	0	0	0	0	0	0	0
29	Petroleum - Net	0	0	0	0	0	0	0	0	0	0
30	Biofuel - Net	0	0	0	0	0	0	0	0	0	0
31	Cogeneration - Net	0	0	0	0	0	0	0	0	0	0
32	**Contract Purchases**	627	627	631	281	281	281	281	281	281	281
33	Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
34	Intra-Regional Transfers (In)	350	350	350	0	0	0	0	0	0	0
35	Non-Federal CER	235	235	237	237	237	237	237	237	237	237
36	Slice Transmission Loss Return	41.0	41.0	43.2	43.1	43.2	43.1	43.2	43.1	43.2	43.1
37	**Reserves & Losses**	-2042	-2057	-2043	-2047	-2052	-2059	-2061	-2065	-2066	-2070
38	Operating Reserves	-790	-795	-780	-785	-790	-793	-797	-798	-801	-802
39	Balancing Reserves	-878	-886	-886	-886	-886	-886	-886	-886	-886	-886
40	Transmission Losses	-374	-376	-377	-376	-375	-379	-378	-381	-379	-382
41	**Total Net Resources**	**11592**	**11576**	**11665**	**11288**	**11306**	**11277**	**11297**	**11270**	**11292**	**11250**
42	**Total Surplus/Deficit**	**414**	**199**	**467**	**69**	**98**	**53**	**66**	**10**	**15**	**-123**

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Exhibit 4-4: Monthly 120-Hour Capacity

Federal System Analysis Surplus Deficit
Operating Year 2024
Firm Water Condition

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Loads and Resources - Federal System
Operating Year: 2024 Water Year: P10
2023 White Book - 30WY (2001/P10) Report Date: **12/5/2022**
S241-WB-20230315-141333

	120Hr-MW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
	Firm Obligations	2016	2008	2016	2006	2014	2009	2002	2004	1992	1994	2008	2005	1994	1994
1	**Load Following**	4505	4197	3789	3960	4348	5177	5151	4786	4441	4239	4274	4058	4507	4731
2	Preference Customers	4965	4965	4408	4733	5271	6087	6182	5882	5385	5106	5106	4652	4963	5101
3	Federal Agencies	160	160	148	179	204	225	224	242	209	184	184	163	163	185
4	USBR	620	620	577	407	104	144	201	177	343	425	425	520	600	619
5	Federal Diversity	-1240	-1548	-1344	-1359	-1231	-1280	-1456	-1514	-1497	-1476	-1441	-1276	-1219	-1174
6	**Tier 1 Block**	353	353	606	522	870	897	952	843	847	401	401	149	23.0	339
7	Tier 1 Block	353	353	606	522	870	897	952	843	847	401	401	149	23.0	339
8	**Slice**	2634	2748	2632	2591	3264	3759	3606	3571	3456	2790	2494	3160	3080	2811
9	Slice Block	1131	1131	1114	1136	1322	1510	1494	1331	1276	1178	1178	1133	1084	1120
10	Slice Output from T1 System	1503	1617	1518	1455	1942	2249	2112	2240	2180	1612	1316	2026	1997	1691
11	**Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
12	Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
13	**Contract Deliveries**	1536	1617	1476	1451	1458	1458	1458	1458	1451	1451	1451	1451	1451	1480
14	Exports	1201	1283	1142	1142	1142	1142	1142	1142	1142	1142	1142	1142	1142	1170
15	Intra-Regional Transfers (Out)	334	334	334	309	316	316	316	316	309	309	309	309	309	309
16	**Total Firm Obligations**	**9039**	**8926**	**8514**	**8535**	**9951**	**11301**	**11178**	**10670**	**10205**	**8891**	**8631**	**8829**	**9072**	**9371**
	Net Resources														
17	**Hydro**	9116	9280	8977	8604	10790	11790	11828	11257	11244	8901	7975	11677	10864	10014
18	Regulated Hydro - Net	8658	8675	8591	8095	10341	11443	11287	10893	10924	8418	7343	11137	10320	9422
19	Independent Hydro - Net	455	601	383	505	445	343	536	359	316	479	627	535	540	589
20	Small Hydro - Net	3.49	3.49	3.00	4.11	4.49	4.60	4.59	4.62	4.58	4.58	4.58	4.58	4.09	3.19
21	**Non-Hydro Renewable**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	Wind - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Solar - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Other - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	**Thermal**	1163	1163	1179	1181	1179	1180	1178	1175	1177	1166	1166	1151	1154	1168
26	Nuclear - Net	1163	1163	1179	1181	1179	1180	1178	1175	1177	1166	1166	1151	1154	1168
27	Coal - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Natural Gas - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Petroleum - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Biofuel - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	Cogeneration - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	**Contract Purchases**	271	273	315	414	474	580	627	529	478	417	412	275	282	275
33	Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
34	Intra-Regional Transfers (In)	0	0	50.0	150	200	300	350	250	200	150	150	0	0	0
35	Non-Federal CER	235	235	235	235	235	235	235	235	235	235	235	235	235	235
36	Slice Transmission Loss Return	34.5	37.2	29.5	28.2	37.7	43.7	41.0	43.5	42.3	31.3	25.6	39.3	45.9	38.9
37	**Reserves & Losses**	-1844	-1851	-1864	-1776	-1944	-2039	-2042	-1989	-1967	-1814	-1758	-1942	-1913	-1873
38	Operating Reserves	-660	-662	-619	-626	-725	-789	-790	-756	-734	-654	-625	-697	-687	-676
39	Balancing Reserves	-894	-894	-964	-877	-878	-878	-878	-878	-878	-878	-878	-878	-878	-878
40	Transmission Losses	-290	-296	-281	-274	-341	-372	-374	-355	-355	-282	-255	-367	-348	-319
41	**Total Net Resources**	**8706**	**8864**	**8607**	**8422**	**10499**	**11510**	**11592**	**10972**	**10932**	**8671**	**7795**	**11161**	**10387**	**9584**
42	**Total Surplus/Deficit**	**-333**	**-62**	**93**	**-113**	**548**	**209**	**414**	**302**	**727**	**-221**	**-836**	**2,332**	**1,315**	**213**

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Federal System Analysis Surplus Deficit
Operating Year 2024

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Federal Report Surplus Deficit By Water Year
Operating Year 2024
2023 White Book - 30WY Report Date: **12/5/2022**
S241-WB-20230315-141333

Energy-aMW - Surplus Deficit	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
1 1989 Federal Report Surplus Deficit	214	991	-258	-603	215	-106	-60.4	-1090	932	1803	2926	2754	1969	285	588
2 1990 Federal Report Surplus Deficit	258	143	-18.0	-230	920	768	1688	3631	1085	1613	2472	2424	4361	2263	1581
3 1991 Federal Report Surplus Deficit	2206	2211	127	-387	2374	1418	3021	3945	2571	2004	1452	2829	3954	3733	2287
4 1992 Federal Report Surplus Deficit	2628	1996	-32.6	-280	383	-1035	-24.2	771	-468	-95.6	-214	2342	1146	-272	388
5 1993 Federal Report Surplus Deficit	115	-32.8	60.5	-623	208	-652	-953	-1595	264	287	-1013	3459	2788	1067	315
6 1994 Federal Report Surplus Deficit	665	516	470	-229	294	-610	-732	-192	-112	-443	783	1761	1239	158	233
7 1995 Federal Report Surplus Deficit	70.9	-240	60.1	-439	116	-329	119	1238	2643	550	155	2274	3978	2143	1003
8 1996 Federal Report Surplus Deficit	717	765	553	761	2871	5040	5419	5794	5744	2630	4122	3617	4732	4688	3607
9 1997 Federal Report Surplus Deficit	2362	2614	351	15.8	796	1561	5600	5496	4913	3189	5466	5756	6411	4996	3555
10 1998 Federal Report Surplus Deficit	2751	3082	1423	2265	1803	451	1412	2787	1376	490	555	5044	4360	2561	2243
11 1999 Federal Report Surplus Deficit	2475	1325	387	-214	-76.9	812	4220	3896	5348	2213	3102	3164	4802	4645	2627
12 2000 Federal Report Surplus Deficit	2972	3361	129	-155	1980	1976	2557	2585	2546	2515	3137	2966	2164	1232	1997
13 2001 Federal Report Surplus Deficit	1450	-29.9	-46.0	-224	46.8	-886	-702	3.36	-373	-939	-1562	619	558	-23.7	-133
14 2002 Federal Report Surplus Deficit	372	-158	-224	-687	-271	-274	-427	-211	409	1166	2787	2553	4514	3287	895
15 2003 Federal Report Surplus Deficit	1332	1164	26.1	-280	394	-767	-555	324	1714	1091	1194	1877	3767	108	745
16 2004 Federal Report Surplus Deficit	-250	-145	-120	-444	912	340	-231	-831	318	587	553	1972	2744	704	479
17 2005 Federal Report Surplus Deficit	-366	413	220	403	832	1174	1063	2526	584	-498	-432	1566	2237	1405	959
18 2006 Federal Report Surplus Deficit	415	53.9	57.4	-634	832	359	2827	4275	1837	3181	2547	4639	3469	2144	1896
19 2007 Federal Report Surplus Deficit	289	-75.8	-85.0	-443	531	467	2408	1206	3971	2162	1527	2568	2590	1325	1376
20 2008 Federal Report Surplus Deficit	16.3	-284	-333	-462	608	-583	665	725	911	230	-522	3400	5463	2893	1082
21 2009 Federal Report Surplus Deficit	1169	1462	271	-274	491	-741	1913	658	-301	2625	2135	2752	2655	686	981
22 2010 Federal Report Surplus Deficit	-109	-626	-60.5	-357	231	-160	-875	-567	-589	21.3	-656	693	4264	2032	324
23 2011 Federal Report Surplus Deficit	329	-83.8	269	-406	-34.9	938	3067	4229	2993	4829	2015	4077	6699	6345	2634
24 2012 Federal Report Surplus Deficit	3565	2328	437	145	646	197	1578	2463	3390	4679	5187	4159	5410	5041	2608
25 2013 Federal Report Surplus Deficit	2822	2643	85.0	-178	1560	2101	1097	996	323	3751	2009	3466	3518	2328	1743
26 2014 Federal Report Surplus Deficit	988	327	353	-101	271	-615	1936	-227	3547	3522	2550	3610	3648	2570	1563
27 2015 Federal Report Surplus Deficit	1888	1303	239	-364	1495	1939	2729	3796	4259	1814	87.1	890	890	-407	1494
28 2016 Federal Report Surplus Deficit	-49.4	-308	-296	-405	53.9	-13.2	502	-163	3754	3062	3423	2933	1892	493	987
29 2017 Federal Report Surplus Deficit	72.4	-127	141	-428	2018	554	2544	2692	6325	5162	4785	5860	5350	1739	2639
30 2018 Federal Report Surplus Deficit	1900	1138	-32.9	-329	-334	565	3286	4230	3423	2966	2307	5347	3770	1170	2098

Ranked Averages

31 **Bottom 10 pct**	**-4217**	**-4449**	**-4052**	**-3991**	**-4651**	**-5562**	**-5591**	**-5000**	**-4695**	**-4226**	**-4302**	**-3853**	**-3963**	**-4579**	**-133**
32 **Middle 80 pct**	**-3343**	**-3438**	**-3281**	**-3317**	**-3616**	**-4394**	**-4262**	**-3815**	**-3398**	**-2947**	**-3001**	**-2479**	**-2447**	**-3351**	**1032**

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Water-Year Percentile by Month
Operating Year 2024 - 2033

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		Hydro Modeling 14 - Period													
	Water Year	Aug - I	Aug - II	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr - I	Apr - II	May	Jun	Jul
Firm Water Condition - P10	Energy aMW														
	OY2024	2016	2008	2002	1989	2011	1993	2010	1994	1994	2010	2008	2005	1994	2003
	OY2025	2016	2008	2002	1989	1989	1993	2010	1994	1994	1992	2008	1994	2005	2001
	OY2026	2016	2008	2002	1989	1989	1993	2010	1994	1994	2010	2008	2005	1994	2003
	OY2027	2016	2008	2002	1989	2011	1993	2010	1994	1994	1992	2008	1994	2005	2001
	OY2028	2016	2008	2002	1989	1989	1993	2010	1994	1994	2010	2008	2005	1994	2003
	OY2029	2016	2008	2002	1989	2011	1993	2010	1994	1994	1992	2008	1994	2005	2001
	OY2030	2016	2008	2002	1989	1989	1993	2010	1994	1994	2010	2008	2005	1994	2003
	OY2031	2016	2008	2002	1989	2011	1993	2010	1994	1994	1992	2008	1994	2005	2001
	OY2032	2016	2008	2002	1989	1989	1993	2010	1994	1994	2010	2008	2005	1994	2003
	OY2033	2016	1995	2002	1989	1989	1993	2001	1994	1994	1992	2008	1994	2005	2001
	120HR-MW														
	OY2024	2016	2008	2016	2006	2014	2009	2002	2004	1992	1994	2008	2005	1994	1994
	OY2025	2016	2008	2016	2006	2010	2009	2002	2016	1992	1994	2008	1994	1992	2001
	OY2026	1993	2017	2016	2006	1999	2003	2002	2016	1992	1994	2010	2005	1994	1994
	OY2027	1993	2008	2016	2006	1999	2003	2001	2016	1992	1994	2010	1994	2005	2001
	OY2028	2010	2017	2016	2006	1999	2003	2002	2016	1992	1994	2010	2005	1994	1994
	OY2029	1993	2008	2016	2006	1999	2003	2001	2016	1992	1994	2010	1994	2005	2001
	OY2030	2010	2017	2016	2006	1999	2003	2002	2016	1992	1994	2010	2005	1994	1994
	OY2031	1993	2008	2016	2006	1999	2003	2001	2016	1992	1994	2010	1994	2005	2001
	OY2032	2010	2017	2016	2006	1999	2003	2002	2016	1992	1994	2010	2005	1994	1994
	OY2033	1993	2008	2016	2006	1999	2003	2001	2016	1992	1994	2010	1994	2005	2001
Median Water Condition - P50	Energy aMW														
	OY2024	1994	2005	2006	2018	2007	2004	1998	1995	2003	1991	2011	1991	2013	2017
	OY2025	2003	2005	2006	2018	2007	2004	1998	2007	2003	1990	2011	1999	2003	2006
	OY2026	1994	2005	2006	2018	2009	2004	2012	1995	2006	2015	2011	2000	2003	2017
	OY2027	1996	1999	2006	2018	2007	2004	1998	1995	2003	2015	2011	2009	2013	2006
	OY2028	1994	2005	2006	2018	2007	2004	1998	1995	2006	2015	2011	1991	2003	2010
	OY2029	2003	1999	2006	2018	2009	2004	1998	1995	2003	2015	2011	2016	2006	1993
	OY2030	1994	2005	2006	2018	2009	2006	1998	1995	2006	1991	2011	1991	2006	2017
	OY2031	2003	2005	2006	2018	2009	2004	1998	2007	2006	2015	2011	2016	2006	1993
	OY2032	1994	2005	2006	2018	2009	2004	2012	2007	2006	1991	2011	2000	2006	2017
	OY2033	2003	2005	1995	2003	2009	2004	1998	1995	2003	2015	2013	2009	2006	2006
	120HR-MW														
	OY2024	2014	2005	1990	1992	2012	2017	2005	2007	2006	2015	2013	2016	2018	2017
	OY2025	2017	1999	1990	2009	2009	2004	2009	1995	2006	1991	2013	1989	1998	1993
	OY2026	1994	2005	2018	2009	2003	2004	2009	1995	2006	1989	2013	2016	2018	2017
	OY2027	2003	1999	1990	2017	2012	2017	2009	1995	2006	1991	2013	1989	2018	2006
	OY2028	1994	2005	2018	2009	2009	2004	2009	1995	2006	1989	2013	2016	2018	2017
	OY2029	2014	1999	1990	2017	2012	2004	2012	1995	2006	1990	2011	1995	2018	2006
	OY2030	1994	2005	2018	2009	2003	2004	2009	1995	2006	1990	2013	2000	2018	2017
	OY2031	2003	1999	1990	2017	2009	2004	2012	1995	2006	1991	2013	1995	2014	2006
	OY2032	1994	2005	2018	2009	2009	2017	2009	1995	2003	1989	2013	2000	2018	2017
	OY2033	2014	1999	2015	2017	2009	2017	2012	1995	2006	1990	2011	1989	2018	2006
High Water Condition - P90	Energy aMW														
	OY2024	1998	1997	2012	2012	2017	2015	2018	2011	1997	2013	1996	1998	2012	1999
	OY2025	1998	1997	2012	2012	2017	2015	2018	2018	1997	1997	2016	1998	2017	1996
	OY2026	1998	2012	2012	2012	2000	2015	2018	2011	1997	2014	1996	1998	2012	1999
	OY2027	1998	1997	2012	2012	2017	2015	2018	2018	1997	2016	1996	2018	2008	1997
	OY2028	2013	1997	2012	2012	2000	2015	2018	2011	1997	2014	1996	1998	2012	1999
	OY2029	1998	1997	2012	2012	2017	2015	2018	2018	1997	2016	1996	2018	2008	1997
	OY2030	2013	1997	2012	2012	2000	2015	2018	2011	1997	2014	1996	1998	2012	1999
	OY2031	1998	1997	2012	2012	2017	2015	2018	2018	1997	2016	1996	2018	2008	1997
	OY2032	2013	1997	2012	2012	2000	2015	2018	2011	1997	2014	1996	1998	2012	1999
	OY2033	1998	1997	2012	2012	2017	2015	2018	2018	1997	2016	1996	2018	2008	1997
	120HR-MW														
	OY2024	1997	1997	1999	2012	1998	2015	1991	2011	2015	2013	2016	1998	2010	1996
	OY2025	2013	1997	1999	2012	1998	2015	1991	2011	2015	2011	1996	1998	2017	2012
	OY2026	2013	2012	1999	2012	2017	2015	1991	2011	2015	2013	2016	1998	2017	1996
	OY2027	1997	2013	1999	2012	1998	2015	1991	2011	2015	2016	1996	2006	2017	1996
	OY2028	1999	1997	1999	2012	2017	2015	1991	2011	2015	2013	2016	1998	2017	1996
	OY2029	1997	2013	1999	2012	1998	2015	1991	2011	2015	2016	1996	2006	2017	1996
	OY2030	1999	1997	1999	2012	2017	2015	1991	2011	2015	2013	2016	1998	2017	1996
	OY2031	1997	2013	1999	2012	1998	2015	1991	2011	2015	2016	1996	2006	2017	1996
	OY2032	1999	1997	1999	2012	2017	2015	1991	2011	2015	2013	2016	1998	2017	1996
	OY2033	1997	2013	1999	2012	1998	2015	1991	2011	2015	2016	1996	2006	1997	1996

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Section 5: Pacific Northwest Regional Analysis Exhibits

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Regional Analysis Surplus Deficit
Operating Year 2024 to 2033
Firm Water Condition

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Loads and Resources - Pacific Northwest Region
Operating Year: 2024 Water Year: P10
2023 White Book - 30WY (2001/P10) Report Date: **12/5/2022**
S241-WB-20230201-101234

	Energy-aMW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	Regional Loads										
1	**Retail Loads**	24164	24439	24600	24808	25001	25170	25266	25339	25378	25470
2	Federal Agency	148	157	163	166	168	169	170	170	170	170
3	USBR	188	188	188	188	188	188	188	188	188	188
4	Cooperative	2854	2995	3078	3200	3322	3380	3419	3440	3453	3474
5	Municipality	2562	2566	2568	2570	2570	2575	2578	2584	2580	2591
6	Public Utility District	4901	4966	5011	5071	5129	5204	5256	5294	5321	5350
7	Investor-Owned Utility	13455	13510	13535	13557	13569	13598	13599	13608	13611	13641
8	Marketer	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50
9	Direct-Service Industry	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3
10	Federal Diversity	0	0	0	0	0	0	0	0	0	0
11	**Exports**	1019	1021	1024	1021	1022	1020	1018	770	675	675
12	Canada	465	468	471	468	469	469	469	469	469	469
13	East Continental Divide	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
14	Inland Southwest	0	0	0	0	0	0	0	0	0	0
15	Pacific Southwest	553	552	552	552	552	550	548	300	205	205
16	Other	0	0	0	0	0	0	0	0	0	0
17	**Total Regional Loads**	**25183**	**25461**	**25624**	**25829**	**26023**	**26190**	**26284**	**26110**	**26053**	**26146**
	Regional Resources										
18	**Hydro**	12081	12110	12061	12099	12062	12099	12062	12099	12061	11981
19	Regulated Hydro - Net	10868	10868	10834	10872	10836	10872	10835	10872	10836	10764
20	Independent Hydro - Net	969	998	984	983	983	983	984	983	983	974
21	Small Hydro - Net	243	244	244	244	243	244	244	244	243	244
22	**Non-Hydro Renewable**	2711	2749	2748	2748	2748	2749	2748	2733	2744	2748
23	Wind - Net	2200	2238	2238	2238	2236	2238	2238	2222	2233	2238
24	Solar - Net	352	353	353	353	353	353	353	353	353	353
25	Other - Net	159	159	158	158	159	159	158	158	158	158
26	**Thermal**	13002	12795	12443	12175	12197	12102	12279	12028	12197	12157
27	Nuclear - Net	1116	994	1116	994	1116	994	1116	994	1116	994
28	Coal - Net	3751	3676	3201	3049	2955	2981	3034	2948	2962	3034
29	Natural Gas - Net	5373	5372	5371	5371	5373	5372	5368	5371	5372	5371
30	Petroleum - Net	0	0	0	0	0	0	0	0	0	0
31	Biofuel - Net	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5
32	Cogeneration - Net	2737	2727	2729	2736	2728	2730	2736	2690	2721	2733
33	**Imports**	588	591	595	599	603	607	610	130	36	36
34	Canada	38.8	38.8	38.8	38.8	38.8	38.8	38.8	36.7	36.5	36.4
35	East of Continental Divide	0	0	0	0	0	0	0	0	0	0
36	Inland Southwest	502	506	509	513	517	521	525	94		
37	Pacific Southwest	47.1	47.1	47.1	47.1	47.1	47.1	47.1	0.0	0.0	0.0
38	Other	0	0	0	0	0	0	0	0	0	0
39	**Reserves & Losses**	-883	-880	-867	-860	-860	-858	-862	-841	-842	-838
40	Operating Reserves	0	0	0	0	0	0	0	0	0	0
41	Balancing Reserves	0	0	0	0	0	0	0	0	0	0
42	Transmission Losses	-883	-880	-867	-860	-860	-858	-862	-841	-842	-838
43	**Total Regional Resources**	**27499**	**27366**	**26980**	**26761**	**26751**	**26699**	**26837**	**26150**	**26197**	**26085**
44	**Total Surplus/Deficit**	**2316**	**1905**	**1357**	**932**	**728**	**509**	**553**	**40**	**144**	**-61**

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Regional Analysis Surplus Deficit
Operating Year 2024
Firm Water Condition

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Loads and Resources - Pacific Northwest Region

Operating Year: 2024 Water Year: P10

2023 White Book - 30WY (2001/P10) Report Date: **12/5/2022**

S241-WB-20230315-141333

	Energy-aMW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
	Regional Loads															
1	**Retail Loads**	24532	24549	22061	21872	23791	27239	27403	25401	23803	22650	22650	22270	23640	25230	24164
2	Federal Agency	124	124	115	140	154	185	187	169	157	145	145	131	131	140	148
3	USBR	330	329	286	123	9.67	10.8	8.39	18.0	61.0	234	234	345	395	427	188
4	Cooperative	2956	2958	2682	2408	2633	3030	3109	2924	2778	2706	2706	2802	3007	3209	2854
5	Municipality	2301	2303	2219	2402	2715	3098	3123	2943	2721	2468	2468	2235	2215	2303	2562
6	Public Utility District	4652	4656	4330	4464	5015	5743	5841	5390	4987	4667	4667	4397	4556	4770	4901
7	Investor-Owned Utility	14113	14123	12374	12278	13209	15116	15078	13901	13044	12374	12374	12305	13281	14326	13455
8	Marketer	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50
9	Direct-Service Industry	52.2	52.2	52.9	53.8	54.2	53.9	54.3	54.0	53.5	53.9	53.9	52.4	52.1	52.1	53.3
10	Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	**Exports**	1065	1328	1114	846	1003	873	679	825	880	1215	1102	1147	1192	1313	1019
12	Canada	512	598	454	454	454	454	454	454	454	454	454	454	454	483	465
13	East Continental Divide	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
14	Inland Southwest	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Pacific Southwest	552	729	659	390	548	417	223	369	425	760	647	692	737	829	553
16	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	**Total Regional Loads**	**25597**	**25876**	**23175**	**22717**	**24794**	**28112**	**28082**	**26225**	**24683**	**23865**	**23753**	**23417**	**24832**	**26543**	**25183**
	Regional Resources															
18	**Hydro**	10268	10424	9680	9468	12772	12264	13459	12220	12157	12010	10436	14953	14121	12294	12081
19	Regulated Hydro - Net	9116	9103	8687	8438	11669	11209	12324	11211	11018	10883	9046	13383	12510	10901	10868
20	Independent Hydro - Net	827	998	749	867	975	929	1012	877	978	846	1108	1167	1189	988	969
21	Small Hydro - Net	325	323	244	163	128	126	124	132	162	280	282	403	422	405	243
22	**Non-Hydro Renewable**	2163	2869	2597	2127	2668	2173	1376	2057	2382	3875	3364	3656	3721	3646	2711
23	Wind - Net	1511	2216	2046	1651	2298	1869	1046	1661	1895	3311	2799	3023	3046	2951	2200
24	Solar - Net	492	492	392	315	211	144	181	236	327	406	406	471	535	513	352
25	Other - Net	160	160	158	161	160	160	149	160	159	158	158	162	140	182	159
26	**Thermal**	13413	13420	13492	13528	13767	13867	13821	13751	12924	12911	11190	10154	11868	13413	13002
27	Nuclear - Net	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116
28	Coal - Net	3821	3822	3825	3826	3824	3828	3828	3827	3799	3654	3457	3216	3842	3824	3751
29	Natural Gas - Net	5585	5592	5654	5719	5851	5921	5914	5853	5804	5484	4427	3403	4232	5587	5373
30	Petroleum - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	Biofuel - Net	23.6	23.6	25.4	26.7	27.0	24.6	24.3	24.4	27.0	25.4	25.4	27.2	25.0	25.8	25.5
32	Cogeneration - Net	2867	2867	2871	2840	2949	2978	2939	2931	2177	2632	2165	2392	2653	2860	2737
33	**Imports**	580	580	510	482	669	770	605	605	508	455	455	503	656	708	588
34	Canada	20.8	20.8	15.8	22.0	38.9	49.3	62.3	70.8	62.7	30.2	30.2	28.9	38.6	27.0	38.8
35	East of Continental Divide	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Inland Southwest	560	559	494	460	449	485	456	471	445	425	425	474	617	681	502
37	Pacific Southwest	0	0	0	0	181	235	87.4	63.3	0	0	0	0	0	0	47.1
38	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39	**Reserves & Losses**	-893	-923	-794	-773	-902	-878	-884	-865	-845	-883	-768	-884	-1026	-1016	-883
40	Operating Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
41	Balancing Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42	Transmission Losses	-893	-923	-794	-773	-902	-878	-884	-865	-845	-883	-768	-884	-1026	-1016	-883
43	**Total Regional Resources**	**25531**	**26370**	**25485**	**24831**	**28974**	**28195**	**28379**	**27768**	**27126**	**28368**	**24676**	**28382**	**29339**	**29045**	**27499**
44	**Total Surplus/Deficit**	**-65.7**	**494**	**2310**	**2113**	**4179**	**82.8**	**297**	**1543**	**2444**	**4503**	**924**	**4966**	**4507**	**2502**	**2316**

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Regional Analysis Surplus Deficit
Operating Year 2024 to 2033
Firm Water Condition

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Loads and Resources - Pacific Northwest Region
Operating Year: 2024-2033 Water Year: P10 - January
2023 White Book - 30WY Report Date: **12/5/2022**

S241-WB-20230209-155822

	120Hr-MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	Regional Loads										
1	**Retail Loads**	34526	34825	35084	35354	35632	35847	36020	36190	36331	36492
2	Federal Agency	232	240	246	248	252	254	255	255	256	256
3	USBR	201	201	201	201	201	201	201	201	201	201
4	Cooperative	4113	4267	4342	4461	4588	4633	4673	4700	4727	4752
5	Municipality	4226	4224	4248	4239	4215	4252	4259	4272	4269	4276
6	Public Utility District	7940	7992	8057	8133	8225	8328	8393	8456	8510	8548
7	Investor-Owned Utility	19202	19296	19386	19471	19552	19619	19676	19737	19805	19871
8	Marketer	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50
9	Direct-Service Industry	65.4	65.4	65.4	65.4	65.4	65.4	65.4	65.4	65.4	65.4
10	Federal Diversity	-1456	-1462	-1465	-1467	-1468	-1509	-1504	-1498	-1505	-1482
11	**Exports**	1143	1143	1143	1143	1143	1143	1143	1143	1143	1143
12	Canada	1142	1142	1142	1142	1142	1142	1142	1142	1142	1142
13	East Continental Divide	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
14	Inland Southwest	0	0	0	0	0	0	0	0	0	0
15	Pacific Southwest	0	0	0	0	0	0	0	0	0	0
16	Other	0	0	0	0	0	0	0	0	0	0
17	**Total Regional Loads**	**35668**	**35968**	**36227**	**36496**	**36774**	**36989**	**37163**	**37333**	**37474**	**37634**
	Regional Resources										
18	**Hydro**	24046	24050	24120	23728	24120	23728	24120	23728	24120	23728
19	Regulated Hydro - Net	22255	22258	22329	22234	22329	22234	22329	22234	22329	22234
20	Independent Hydro - Net	1640	1640	1640	1342	1640	1342	1640	1342	1640	1342
21	Small Hydro - Net	151	151	151	151	151	151	151	151	151	151
22	**Non-Hydro Renewable**	182	182	182	182	182	182	182	182	182	182
23	Wind - Net	0	0	0	0	0	0	0	0	0	0
24	Solar - Net	0	0	0	0	0	0	0	0	0	0
25	Other - Net	182	182	182	182	182	182	182	182	182	182
26	**Thermal**	14910	14910	14106	14106	14106	14106	14106	14046	14106	14106
27	Nuclear - Net	1178	1178	1178	1178	1178	1178	1178	1178	1178	1178
28	Coal - Net	4195	4195	3392	3392	3392	3392	3392	3392	3392	3392
29	Natural Gas - Net	6288	6288	6288	6288	6288	6288	6288	6288	6288	6288
30	Petroleum - Net	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5
31	Biofuel - Net	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6
32	Cogeneration - Net	3179	3179	3179	3179	3179	3179	3179	3119	3179	3179
33	**Imports**	1065	1068	1071	1075	1078	1081	1085	150	150	150
34	Canada	155	155	155	155	155	155	155	150	150	150
35	East of Continental Divide	0	0	0	0	0	0	0	0	0	0
36	Inland Southwest	610	613	616	620	623	626	630	0	0	0
37	Pacific Southwest	300	300	300	300	300	300	300	0	0	0
38	Other	0	0	0	0	0	0	0	0	0	0
39	**Reserves & Losses**	-4085	-4086	-4046	-4032	-4062	-4047	-4075	-4027	-4055	-4037
40	Operating Reserves	-2063	-2056	-2038	-2035	-2054	-2051	-2067	-2061	-2076	-2070
41	Balancing Reserves	-878	-886	-886	-886	-886	-886	-886	-886	-886	-886
42	Transmission Losses	-1144	-1144	-1122	-1110	-1122	-1110	-1122	-1079	-1093	-1081
43	**Total Regional Resources**	**36118**	**36123**	**35433**	**35059**	**35423**	**35049**	**35418**	**34079**	**34503**	**34129**
44	**Total Surplus/Deficit**	**449**	**155**	**-794**	**-1438**	**-1351**	**-1940**	**-1745**	**-3254**	**-2971**	**-3506**

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Exhibit 5-4: Monthly 120-Hour Capacity

Regional Analysis Surplus Deficit
Operating Year 2024
Firm Water Condition

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Loads and Resources - Pacific Northwest Region

Operating Year: 2024 Water Year: P10

2023 White Book - 30WY (2001/P10) Report Date: **12/5/2022**

S241-WB-20230315-141333

120Hr-MW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Regional Loads														
1 **Retail Loads**	31680	31372	27945	27569	30346	34101	34526	31858	30408	28528	28563	27489	30490	32359
2 Federal Agency	172	172	159	195	207	238	232	235	216	200	200	177	179	193
3 USBR	620	620	577	407	104	144	201	177	343	425	425	520	600	619
4 Cooperative	3670	3670	3309	3290	3559	4002	4113	3897	3698	3601	3601	3529	3715	3895
5 Municipality	3189	3189	2922	3220	3700	4219	4226	4032	3727	3415	3415	3006	3045	3210
6 Public Utility District	6408	6408	5795	6127	6899	7780	7940	7485	6981	6515	6515	5961	6149	6365
7 Investor-Owned Utility	18795	18795	16461	15623	17042	18929	19202	17479	16872	15779	15779	15506	17953	19186
8 Marketer	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50
9 Direct-Service Industry	62.8	62.8	63.4	64.6	65.0	65.0	65.4	64.7	65.0	65.4	65.4	64.2	64.3	63 0
10 Federal Diversity	-1240	-1548	-1344	-1359	-1231	-1280	-1456	-1514	-1497	-1476	-1441	-1276	-1219	-1174
11 **Exports**	1519	1601	1460	1151	1143	1143	1143	1143	1143	1143	1151	1151	1460	1488
12 Canada	1201	1283	1142	1142	1142	1142	1142	1142	1142	1142	1142	1142	1142	1170
13 East Continental Divide	1.00	1.00	1.00	1.00	1.00	1 00	1.00	1.00	1 00	1.00	1.00	1 00	1.00	1.00
14 Inland Southwest	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 Pacific Sou hwest	317	317	317	8.04	0	0	0	0	0	0	8.04	8 04	317	317
16 O her	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 **Total Regional Loads**	**33199**	**32973**	**29405**	**28720**	**31489**	**35243**	**35668**	**33000**	**31550**	**29670**	**29714**	**28639**	**31949**	**33847**
Regional Resources														
18 **Hydro**	19826	21048	20711	20447	22370	23411	24046	23433	23158	20624	19793	23875	23091	22206
19 Regulated Hydro - Net	18066	19006	19162	18716	20983	22010	22255	21854	21561	18657	17693	21711	20918	20092
20 Independent Hydro - Net	1397	1682	1268	1534	1223	1245	1640	1415	1394	1648	1779	1723	1715	1675
21 Small Hydro - Net	363	361	280	197	164	156	151	164	203	319	320	441	459	439
22 **Non-Hydro Renewable**	193	193	193	194	193	193	182	194	193	193	193	194	192	192
23 Wind - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24 Solar - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25 O her - Net	193	193	193	194	193	193	182	194	193	193	193	194	192	192
26 **Thermal**	14433	14434	14526	14668	14818	14904	14910	14836	14149	14032	12498	13271	13995	14437
27 Nuclear - Net	1163	1163	1179	1181	1179	1180	1178	1175	1177	1166	1166	1151	1154	1168
28 Coal - Net	4194	4194	4193	4194	4194	4195	4195	4195	4194	4194	4194	3861	4193	4193
29 Natural Gas - Net	5929	5929	5989	6084	6213	6282	6288	6224	6176	5772	4717	5615	5496	5932
30 Petroleum - Net	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5
31 Biofuel - Net	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6
32 Cogeneration - Net	3078	3078	3096	3141	3163	3177	3179	3173	2533	2832	2352	2576	3082	3075
33 **Imports**	942	942	799	739	986	1093	1065	1098	800	705	705	748	1016	1097
34 Canada	146	146	146	147	102	124	155	188	213	147	147	147	146	146
35 East of Continental Divide	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36 Inland Southwest	796	796	653	592	584	669	610	610	587	558	558	601	870	951
37 Pacific Sou hwest	0	0	0	0	300	300	300	300	0	0	0	0	0	0
38 O her	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39 **Reserves & Losses**	-3878	-3945	-3771	-3662	-3884	-4054	-4085	-3973	-3863	-3679	-3541	-3776	-3999	-4015
40 Operating Reserves	-1865	-1890	-1779	-1759	-1914	-2050	-2063	-1968	-1895	-1791	-1724	-1811	-1903	-1933
41 Balancing Reserves	-894	-894	-964	-877	-878	-878	-878	-878	-878	-878	-878	-878	-878	-878
42 Transmission Losses	-1119	-1160	-1028	-1026	-1092	-1126	-1144	-1127	-1091	-1010	-939	-1087	-1218	-1205
43 **Total Regional Resources**	**31516**	**32672**	**32458**	**32386**	**34484**	**35547**	**36118**	**35587**	**34436**	**31875**	**29647**	**34311**	**34296**	**33917**
44 **Total Surplus/Deficit**	**-1683**	**-300**	**3053**	**3666**	**2995**	**304**	**449**	**2587**	**2886**	**2205**	**-66.5**	**5672**	**2346**	**69.7**

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Regional Analysis Surplus Deficit
Operating Year 2024

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Regional Report Surplus Deficit By Water Year
Operating Year 2024
2023 White Book - 30WY Report Date: **12/5/2022**
S241-WB-20230209-155822

	Energy-aMW - Surplus Deficit	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
1	1989 Regional Report Surplus Deficit	1048	2663	2353	2113	4602	1628	906	281	4111	7914	9128	7491	6530	3491	3657
2	1990 Regional Report Surplus Deficit	1187	1259	2912	2784	6174	4224	5277	8719	5011	7696	7589	6827	10534	7174	5680
3	1991 Regional Report Surplus Deficit	4750	5077	3120	2844	9486	4794	6602	10030	7224	8498	5480	7434	9834	10009	6919
4	1992 Regional Report Surplus Deficit	5705	4767	2996	2601	4565	156	1128	3777	1807	3609	1697	5930	3639	1363	2977
5	1993 Regional Report Surplus Deficit	543	541	2490	1840	4053	82.8	-1051	-360	2981	5165	842	8725	7559	4688	2882
6	1994 Regional Report Surplus Deficit	2446	1917	3716	2740	4087	599	-578	1543	2444	3454	4859	5895	4507	2519	2810
7	1995 Regional Report Surplus Deficit	387	299	2672	2294	3967	1606	1615	5162	7606	5269	2346	6985	10604	6568	4422
8	1996 Regional Report Surplus Deficit	2806	2233	3839	4933	10592	11542	11104	14021	13607	10002	11126	9386	11177	10990	9502
9	1997 Regional Report Surplus Deficit	5359	5572	3754	3570	5725	5230	11547	13276	12313	11313	12464	12666	14208	11924	9279
10	1998 Regional Report Surplus Deficit	6562	6973	6144	8501	7851	3326	4421	7735	5517	5734	3848	10768	11178	7579	7040
11	1999 Regional Report Surplus Deficit	5426	3565	3747	2905	4271	4131	9082	9840	12496	9176	8830	8535	12035	11934	7696
12	2000 Regional Report Surplus Deficit	7331	7646	3484	3336	8798	6268	5968	7343	6922	9707	9295	7909	7295	5151	6612
13	2001 Regional Report Surplus Deficit	3430	1493	2905	2860	3676	-241	-923	1970	1274	3124	-653	2574	3115	1937	1892
14	2002 Regional Report Surplus Deficit	816	404	2310	1996	2857	1383	682	2095	3171	6653	7822	7129	10949	9013	4111
15	2003 Regional Report Surplus Deficit	2942	2864	3151	2481	4226	136	417	2998	5707	5970	4658	5779	9333	2502	3730
16	2004 Regional Report Surplus Deficit	-113	405	2467	2667	5338	2427	862	1285	2956	5113	3439	5868	7478	3597	3275
17	2005 Regional Report Surplus Deficit	-135	1621	3524	4027	5520	4291	3239	6364	3412	3115	1535	4966	6391	4607	4104
18	2006 Regional Report Surplus Deficit	1343	906	2851	2104	5263	2617	6995	9985	5934	10743	7990	10357	10448	6041	6059
19	2007 Regional Report Surplus Deficit	1346	743	3415	2172	5516	3038	5326	4942	10064	8792	5768	7116	7721	4914	5204
20	2008 Regional Report Surplus Deficit	1023	494	2872	2132	4204	909	1905	3383	3828	4292	924	8481	12441	8486	4325
21	2009 Regional Report Surplus Deficit	3407	3564	3306	2565	4967	501	4174	3143	1747	9118	6559	7503	8249	3629	4246
22	2010 Regional Report Surplus Deficit	674	-4.39	2990	2421	4192	1231	297	1538	1339	4503	629	3144	10860	6633	3115
23	2011 Regional Report Surplus Deficit	1953	1078	3236	2482	4179	3867	7423	10522	8708	13224	7355	9799	14280	14397	7536
24	2012 Regional Report Surplus Deficit	8140	5818	3933	3634	5154	2129	4420	6692	8631	12646	11996	9902	12091	12087	7320
25	2013 Regional Report Surplus Deficit	6043	5778	3320	2880	7163	5930	2909	4099	2894	11307	6046	8335	9581	6540	5679
26	2014 Regional Report Surplus Deficit	2345	1566	3658	3263	4336	459	4401	1801	9357	10528	7553	8550	9600	7971	5370
27	2015 Regional Report Surplus Deficit	4230	3368	3206	2745	7043	5802	6382	10091	10039	7906	2578	3127	3639	1150	5165
28	2016 Regional Report Surplus Deficit	-65.7	-10.7	2790	1981	3588	2212	2444	2606	9359	10517	9398	7663	5928	2830	4271
29	2017 Regional Report Surplus Deficit	485	503	2827	3293	8452	3048	5434	7827	14454	14576	11750	11956	12517	5696	7408
30	2018 Regional Report Surplus Deficit	4428	2864	2875	2804	4026	3090	7205	10317	8687	10241	8275	11303	10132	4949	6500
	Ranked Averages															
31	**Bottom 10 pct**	**-9987**	**-9578**	**-7078**	**-7069**	**-8207**	**-11811**	**-12756**	**-10308**	**-9347**	**-7144**	**-9197**	**-9536**	**-9137**	**-9376**	
32	**Middle 80 pct**	**-6477**	**-6264**	**-4141**	**-4264**	**-4433**	**-7781**	**-8291**	**-6111**	**-5180**	**-3046**	**-5140**	**-4758**	**-4121**	**-5244**	**4261**

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Appendix A - Reports Available Upon Request OY2024 - 2033

1. Annual Energy

1.1. Federal Report Surplus/ Deficit – Annual
1.2. Regional Report Surplus/ Deficit – Annual
1.3. Regional Total Retail Load – Annual
1.4. Regional Exports – Annual
1.5. Regional Imports – Annual
1.6. Regional Intra-Regional Transfer – Annual
1.7. BPA Sales to Preference and Legacy Customers – Annual
1.8. Regional Regulated Hydro – Annual
1.9. Regional Independent Hydro – Annual
1.10. Regional Small Hydro – Annual
1.11. Regional Non-Hydro Renewable – Wind – Annual
1.12. Regional Non-Hydro Renewable – Solar – Annual
1.13. Regional Non-Hydro Renewable – Other – Annual
1.14. Regional Thermal – Nuclear – Annual
1.15. Regional Thermal – Coal – Annual
1.16. Regional Thermal – Natural Gas – Annual
1.17. Regional Thermal – Petroleum – Annual
1.18. Regional Thermal – Biofuel – Annual
1.19. Regional Thermal – Cogeneration – Annual
1.20. Non-Federal CER Deliveries to BPA – Annual
1.21. Federal Report Surplus/ Deficit by 80 Water Year – Annual
1.22. Regional Report Surplus/ Deficit by 80 Water Year – Annual

2. Monthly Energy

1.1. Federal Report Surplus/ Deficit – Monthly
1.2. Regional Report Surplus/ Deficit – Monthly
1.3. Regional Total Retail Load – Monthly
1.4. Regional Exports – Monthly
1.5. Regional Imports – Monthly
1.6. Regional Intra-Regional Transfer – Monthly
1.7. BPA Sales to Preference and Legacy Customers – Monthly
1.8. Regional Regulated Hydro – Monthly
1.9. Regional Independent Hydro – Monthly
1.10. Regional Small Hydro – Monthly
1.11. Regional Non-Hydro Renewable – Wind – Monthly
1.12. Regional Non-Hydro Renewable – Solar – Monthly
1.13. Regional Non-Hydro Renewable – Other – Monthly
1.14. Regional Thermal – Nuclear – Monthly
1.15. Regional Thermal – Coal – Monthly
1.16. Regional Thermal – Natural Gas – Monthly
1.17. Regional Thermal – Petroleum – Monthly
1.18. Regional Thermal – Biofuel – Monthly
1.19. Regional Thermal – Cogeneration – Monthly
1.20. Non-Federal CER Deliveries to BPA – Monthly
1.21. Federal Report Surplus/ Deficit by 80 Water Year – Monthly
1.22. Regional Report Surplus/ Deficit by 80 Water Year – Monthly



BONNEVILLE POWER ADMINISTRATION
DOE/BP-5226 ▪ April 2023

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

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 1-120:
2024 Bonneville "White Book"

2024 Pacific Northwest Loads and Resources Study

August 2024





2024 PACIFIC NORTHWEST LOADS AND RESOURCES STUDY

The White Book

BONNEVILLE POWER ADMINISTRATION
August 2024

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

The John Day Dam is one of the four Federal projects located on the Lower Columbia River in the Pacific Northwest; it is part of the Columbia River Basin hydro projects. It is located to the east of The Dalles and right near the mouth of the John Day River. The John Day Dam was constructed between 1958 and 1971, it was built and operated by the U.S. Army Corps of Engineers.

The John Day Dam is a run-of-river type of Dam, and it has a navigation lock, as well as fish ladders on both sides of the project.

For more information on The John Day Dam, please visit John Day Lock & Dam at https://www.nwp.usace.army.mil/John-Day/

ACKNOWLEDGMENTS

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

Bonneville Power Administration

Generation Asset Management:

Long Term Power Planning Group
Regional Coordination Group
Operational Planning Group

Customer Support Services:

Load Forecasting and Analysis Group

Bulk Marketing and Transmission Services:

Long Term Sales and Purchasing Group

NW Requirements Marketing:

Office of General Counsel

Pacific Northwest Utilities Conference Committee

Northwest Power & Conservation Council

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Department of Energy

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

August 15, 2024

In reply refer to: PGPR-5

Dear Interested Parties:

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

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

In recent news, the U.S. and Canada have reached a historic milestone in the years-long effort to modernize the Columbia River Treaty. The two countries reached an agreement in principle outlining a framework for managing our shared resource, the Columbia River, in a way that will deliver tremendous value on both sides of the border. However, since this news is so late breaking, the 2024 White Book does not reflect the agreement in principle. BPA plans to incorporate these changes in future studies including the next white book. For more information, see statement from the White House or fact sheet from the State Department.

The White Book has traditionally included different types of power planning forecasts showcasing BPA's and the region's ability to meet loads under different conditions and time periods. Some examples of the generation metrics include:

- Average energy per month,
- Average energy per year,
- 1 hour peak capacity per month,
- 50 hours per week sustained capacity, and
- 120 hours per month (January) sustained capacity

BPA's goal is to provide meaningful planning forecasts to the region by keeping up with emerging power markets, regional resource adequacy programs, FCRPS capabilities, climate change signals, and a host of other factors. To that end, BPA has decided not to include data related to its 120hr January sustained capacity metric in the 2024 White Book. BPA plans to review its capacity metrics and potentially make changes that would lead to more meaningful forecasts for regional stakeholders.

This 2024 White Book presents Federal system and the region's load obligations, contracts, and resources as of December 2023 for operating years (OY) 2025 through 2034. The 2024 White Book includes the following studies:

- **Federal System Analysis—**forecast of Federal system firm loads and resources based on expected load obligations and different levels of generating resources that vary by different energy planning. The results are summarized below:
  - Annual Energy Surplus/Deficits: Under firm; the Federal system is projected to have annual energy deficits across the study period, ranging from deficits of 79 aMW to 303 aMW. Overall, these annual energy deficit projections are less than those projected in the 2023 White Book. Under median water conditions, the Federal system is projected to have annual energy surpluses through the study period.
- **PNW Regional Analysis—**forecast of regional firm loads and resources, based on expected retail loads and different levels of generating resources that vary by water conditions. The decommissioning of existing resources, the availability of uncommitted PNW Independent Power Producer (IPP) generation, and new resource additions are key variables in the results of this analysis. The results are summarized below:
  - Annual Energy Surplus/Deficits: Under firm water conditions, the PNW region is projected to have an annual energy surplus as large as 1,426 aMW in OY 2025, rather sharply decreasing to a deficit of 2,738 aMW by OY 2034. This result was mainly driven by the increasing PNW Retail Loads. These annual energy projections are more deficit throughout the study period than was forecasted in the 2023 White Book. Under median water conditions, the PNW region would begin to see energy deficits in the out years.

BPA is currently working on its 2024 Resource Program designed to evaluate long-term power resources acquisition strategies. Many factors contribute to the uncertainty of the longer-term resources outlook for the region, such as resource retirements and development, resource adequacy and the efforts surrounding it, carbon free resource requirements, and the most recent Climate Resiliency efforts. As with resources, there is also much uncertainty with loads including the potential for electrification. The 2024 White Book is available on BPA's website: *https://www.bpa.gov/energy-and-services/power/resource-planning* or from BPA's Visitor Center, which you can reach toll-free at 800-622-4520 (or 503-230-4636). Details regarding regional loads, contracts, and generating resources are available upon request. The available report list can be found in the Appendix.

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

Sincerely,

MICHELLE CATHCART

Digitally signed by MICHELLE CATHCART
Date: 2024.08.26 19:13:13 -07'00'

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

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SECTION 1: SUMMARY

Planning Context

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

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

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

The total retail load, contracts, and generation forecasts used in this study were updated as of December 31, 2023. The 2024 White Book supersedes the 2023 White Book and is published as a single summary document.

[1] As defined in the Northwest Power Act

[2] Bonneville Power Administration Climate Change & FCRPS

[3] Operating Year (OY) is the time frame August 1 through July 31. For example, OY 2024 is August 1, 2023 through July 31, 2024.

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

Load Obligations

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

Forecasts of the regional TRL and Federal system load obligations are produced by Bonneville's Agency Load Forecasting (ALF) system. ALF forecasts are completed for individual PNW entities under one of two approaches, the largest share of load forecasts is now based on statistically adjusted end-use models while other forecasts are based on time-series-based regressions that follow the fundamental assumptions of historical retail electricity consumption patterns continuing. The statistically adjusted end-use models include calculated indexes for heating and cooling equipment, and other components. ALF forecasts also assume normal weather conditions and do not include any explicit adjustments for the impacts of climate change or the Inflation Reduction Act[4] (IRA); however, the forecasts do use normalized temperatures based on recent history in order to incorporate recent climate trends. Contract obligations not associated with Bonneville's Preference Power Sales Contracts follow individual contract terms through the life of the contract and are not assumed to be renewed. All Federal system load and contract obligations are assumed to be firm and served by Bonneville regardless of weather, water, or economic conditions.

Resource Types

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

[4] Inflation Reduction Act | U.S. Department of the Treasury

Hydro Resources

- Regulated Hydro – Regulated hydro projects mainly consist of PNW Columbia River Basin hydro power projects for which the operation and generating capability is hydraulically linked. Bonneville forecasts the coordinated energy and capacity production from these hydro power projects using its Hydro-system Simulator (HYDSIM) model. The HYDSIM model considers individual project operating characteristics and conditions to determine energy production expected on a project-to-project basis. Generation forecasts for these projects incorporate the month-to-month power and non-power requirements under each of the 30-historical streamflow conditions of record, 1989 through 2018. The HYDSIM model is described further in the Hydro Resource Modeling section.
- Independent Hydro - Independent hydro projects include those hydro projects whose generation output typically varies by water condition and are not operated or hydraulically linked to part of the Columbia River Basin. Independent hydro generation forecasts can vary month-to-month for energy and capacity and are developed and provided by individual project owners/ operators for the same 30-historical water conditions as the Regulated Hydro projects (1989 through 2018).
- Small Hydro – Small hydro project generation forecasts are either provided by individual project owners or are based on historical actual generation. These generation forecasts vary month-to-month, however they are not assumed to vary by water conditions.

Non-Hydro Resources

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

Thermal Resources

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

Forecasts are adjusted to show actual operational capabilities and expectations, and not to reflect economic dispatch.

Contract Purchases/ Imports

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

Adjustment to Resources

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

- Operating and Balancing Reserves: Operating reserves consist of both spinning and non-spinning contingency reserves that respond to the unforeseen loss of a resource, which are calculated by summing three percent of forecast load and three percent of forecast generation. Balancing reserves consist of regulating, load following, and imbalance reserves that are dedicated to maintaining within-hour load and resource balance. Details in modeling of reserves are described in the Hydro Resource Modeling section. Reserve forecasts included in this White book are modeled consistent with those used in Bonneville's BP-24 Rate Case process.
- Transmission Losses: During the transmission of power to load centers some of the electrical energy is lost, typically in the form of heat, which is categorized as transmission losses. Transmission loss factors are calculated monthly and vary by seasonal generation, e.g. summer months versus winter months. Transmission Loss factors are applied to the sum of all generation and contract purchase forecasts. The monthly transmission loss factor has several components that combine to give the estimate of losses associated with Federal system generation: 1) step-up transformers from generation to the high-voltage transmission network; 2) high-voltage network transmission; 3) transfers to Federal loads over non-Federal transmission systems; and 4) step-down transformers from high-voltage transmission to low-voltage delivery. The Federal system transmission loss factors used in this White Book are consistent with those used in Bonneville's BP-24 Rate Case process:
    - Energy: 3.11 percent from September through May, and 3.16 percent from June through August.

- Capacity: 3.16 percent from September through May, and 3.21 percent from June through August.

Hydro Resource Modeling

The HYDSIM hydro regulation model forecasts the energy production from the regulated hydroelectric power projects in the PNW. This includes the 14 federal hydroelectric projects that make up the Columbia River Federal system, and other major hydro projects in the PNW. Project level generation forecasts are produced in a continuous study for each month of the 30 year-historical streamflow record[5]: October 1989 through September 2018. Energy production is maximized by coordinating hydro operations while meeting power and non-power requirements. HYDSIM produces results for 14 periods: ten complete months plus two periods each for April and August. April and August are divided, first half -second half, due to natural streamflow and significant operational changes happening during these two months. Consequently, generations can differ significantly between the beginning and end of these months. For simplicity, the 14-period results are referred to as "monthly" values in this report.

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

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

The PNCA coordinates the planning and operation of the members' hydroelectric power projects in the PNW. PNCA project owners provide physical plant data as well as power and non-power constraints in an annual data submittal to the Western Power Pool (WPP). Bonneville incorporates this data into HYDSIM to simulate the coordinated operation of the PNW hydro system. This coordination agreement expires on September 15, 2024. As with previous White Books, PNCA assumptions were included past the PNCA expiration date through the 10-year study horizon. The 2025 White Book will include studies that reflect the expiration of the PNCA.

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

[5] 2020 Modified Flows

completed, if agreed upon, in the year prior to the operating year. The Canadian project operations simulated in HYDSIM are based on the best available information from the Treaty planning and coordination process. Canadian operations included in this White Book are based on the official 2022 AOP studies, with additional modifications that reflect updates used in the official 2024 DOP studies.

Both the United States and Canada can terminate most of the provisions of the Treaty any time after September 16, 2014, with a minimum of 10 years advance notice. Neither Canada nor the United States have provided notice of termination; therefore, this study assumes the Treaty continues throughout the study period. Flood Risk Management (FRM) provisions in the Treaty are specified to change in OY25; as of the study vintage the way the FRM will change remained uncertain. This study extends FRM provisions in place for OY24 through the study period.

Bonneville has other operational agreements with Canada that are not part of the Treaty. One operational agreement is the Non-Treaty Storage Agreement (NTSA) that allows additional shaping of Columbia River flows for fish and power operations by utilizing storage not specified by the Treaty from Canadian reservoirs. The NTSA allows water to be released from Canadian project storage during the spring of dry years, it also allows water to be stored in the spring during years when flow targets from the 2008 NOAA BiOp would be met with a subsequent release of water in the summer. These operations are included in this study based on the NTSA signed with British Columbia Hydro in April 2012, which expires on September 15, 2024. This study assumes the NTSA continues through the study period.

Balancing reserves, both incremental and decremental, reduce the ability to shape the Federal system generation. Incremental reserves are modeled by reducing the generation capability of projects. In this study, the impacts of incremental reserves are shown as a reduction in the capacity analyses and are categorized as operating and balancing reserves. Decremental reserves are not specifically reported in this study as they do not cause a limitation in generation capability.

Firm planning

Bonneville bases its resource planning on firm expected generation to ensure sufficient generation to meet obligation loads. Firm conditions are defined as when the PNW hydro system would be the most limited, due to a combination of operational constraints and low water conditions. For the Federal System this is established by considering the historical streamflow record, power and non-power operation constraints, the planned operation of non-hydro resources, combined with the system load requirements. For operational purposes, Bonneville considers firm condition to be the tenth percentile (P10) of the monthly Tier One System Firm Critical Output (T1SFCO) system results. The percentile approach eliminates the anomalies observed in any single water year, e.g. 1937; it also aligns with metrics used in Bonneville's Resource Program. For additional details, please refer to Bonneville's news release BPA adopts new streamflow forecast to reflect changing climate (Augus 1st, 2022) and Climate Change Resiliency Letter to the region (June 6, 2022).

Variability of Hydro Generation

The generating capacity of the Federal system and PNW regional hydro projects depends on several factors: 1) the amount of water flowing through the facilities, 2) the physical capacity of the facilities, 3) any flow or operating requirements, including those pursuant to biological opinions, court orders or

applicable agreements, and 4) other operational limitations. Water conditions cause hydro generation to vary greatly year to year depending on weather factors such as precipitation, snowpack, and temperature. Project-level generation forecasts for regulated hydro resources are produced using HYDSIM for each of the 30 historical streamflow conditions of record, which are based on the period from 1989 through 2018. Additionally, Federal independent hydro project generation was updated by the Army Corps of Engineers, the Bureau of Reclamation, and other project owners incorporating the 2020 modified flows and up to date project operations.

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

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

Hydro Capacity Modeling

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

For hydro resources, the 120-hour capacity forecasts are created by evaluating hourly generation from RiverWare over a specific period of time. This capacity metric is defined as the average generation forecasts from the six highest heavy load hours (HLH) per day, five days per week, and for four weeks per month (6x5x4 = 120 hours). While available, the White Book does not include 1-hour capacity forecasts because this metric does not represent a sustainable generation but rather a single hour peak, meaning it does not consider the ability of the hydro system to sustain generation level over a multiple hour period

The 120-hour capacity forecasts are not included in this (2024) White Book as Bonneville is currently working on improving its capacity metrics to better inform the region of the system's capacity while incorporating climate change, hydro modeling updates, and many ongoing improvements.

Notable Updates

The 2024 White Book includes updated forecasts of Federal system power sales contracts (PSC) obligations, PNW regional Total Retail Loads (TRL), contract purchases, and generation as of December 1, 2023, including:

- Hydro generation modeling excluded Lack-of-Market Spill study which puts upward pressure on generation values especially during runoff periods i.e. April through June.

- Updated RiverWare calibration on project behavior to correct 1) unrealistic results on peaking capacity and 2) violations to meeting Chum salmon requirements in the lower Columbia River and lower Snake River projects.
- Retirement dates associated with planned thermal generation projects.

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

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

Sources of Uncertainty

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

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

- Changes to Treaty obligations and/or operations at the time the study was run,
- PNW entities' ability to purchase power from new and existing uncommitted regional resources to serve retail load,
- PNW entities' ability to purchase and transmit power from extra-regional import/export markets,
- Future climate change impacts to retail loads, streamflow, and resources,

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

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SECTION 2: FEDERAL SYSTEM ANALYSIS

The Federal System Analysis provides a deterministic forecast of the federal system loads and resources over a 10-year period from OY2025 through 2034. This analysis incorporates forecasts of the Federal system's firm requirement PSC obligations, contract sales and purchases, and resource generations. This section presents firm Federal system load and resource forecasts for energy. Additional detailed components of the Federal system study are available only upon request, a list of available reports can be found in the Appendix.

Load Obligations

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

USBR obligations

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

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

In December of 2008, Bonneville executed RD PSCs with public, cooperative, and tribal utilities, as well as federal agency customers. Bonneville is obligated to provide firm power deliveries from October 1, 2011, through September 30, 2028. Customers were offered three types of products: Load Following, Slice/Block, and Block. A total of 134 customers signed the RD contracts, and in this current period 121 are Load Following customers, 10 are Slice/Block, and three are Block.

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

[6] "Through the contracts and rate methodology, each public utility will get a High Water Mark (HWM) that defines its right to buy an amount of power at BPA's lowest cost-based Tier 1 rate. Power above the HWM must be purchased from either non-Federal resources or from BPA at rates reflecting BPA's marginal cost of acquiring the additional power, or through a mix of BPA Tier 2 priced power and non-Federal resources. (P.4 Regional Dialogue July 2007)

non-Federal resources; and/or 3) requesting Bonneville to supply additional power. The current customer elections have been set through fiscal year (FY) 2025, and this study assumes that current elections for FY2025, continue throughout the study period. Based on this assumption, Federal system RD PSC obligation forecasts include elected and forecasted A-RHWM load for the study period. Table 2-1 presents the A-RHWM load included in Bonneville's obligations by FY, which are consistent with the BP-24 Final Rate Proposal following the Rate Settlement for BP24 Rate Case.

Table 2-1 Above Rate-High-Water-Mark Obligations (BP24 Rate Case)

FY	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy aMW	382.1	407.6	433.9	460.3	495.4	515.7	536.2	548.6	575.4	602.9

IOU Load Service under Regional Dialogue (RD) PSCs

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

Direct Service Industrial (DSI) Contracts

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

Other Contract Obligations

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

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

Conservation

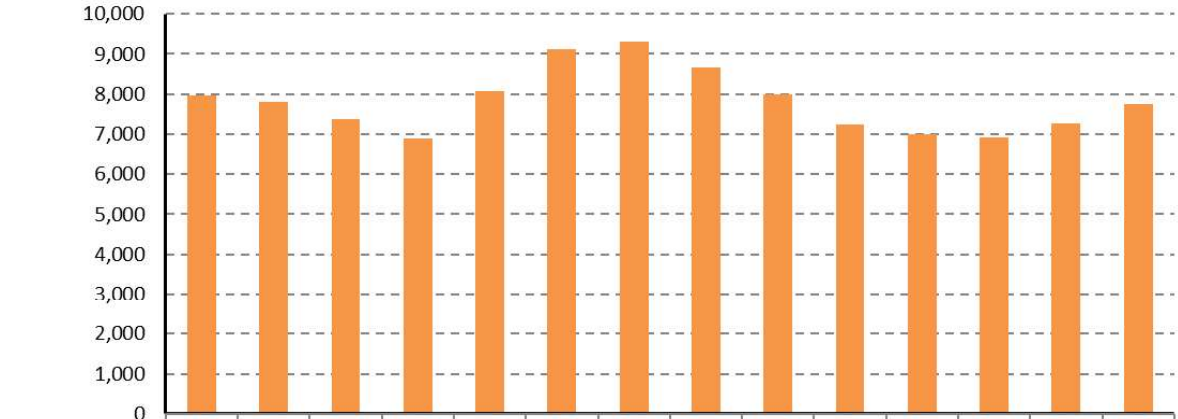
The PSC obligation forecasts developed by the ALF are expected load forecasts, which include conservation identified by individual Bonneville customers. As an embedded assumption in the load forecasts, it is expected that the historically embedded amount of conservation acquired will continue at the same rate going forward across the study period.

Firm Loads

The federal system total firm load forecast shows a 0.24 percent average annual load growth over this study period. While Bonneville's forecast of PSC requirement loads increased roughly 8 percent over the study period, Bonneville's Exports and Intra-Regional Transfers significantly decreased (almost 40%) due to the expiration of contracts. Other Contract Obligations that expire this time include Federal system power sales and Federal system capacity sales.

Overall, the total Federal system load obligations remain relatively flat on an annual basis over the study period which is consistent with previous White Book studies due to the nature of Bonneville's RD PSCs. While on an annual basis these obligations demonstrate little variation across the study period, Bonneville's loads can vary greatly throughout the year. At a high level, Bonneville[7] experiences its highest loads in the late fall and winter months (November through March) primarily due to heating loads, with lower loads during spring, early summer and early fall months when temperatures are mild. July and August loads tend to be slightly higher than the rest of the summer months due to increasing air conditioning demands. Table 2-2 illustrates the monthly shape of the forecasted Federal system firm load obligations for OY2025.

Table 2-2 Federal System Firm Obligations for OY2025 - Monthly



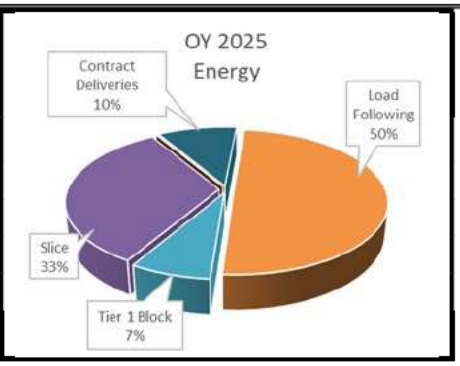
	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	7961	7810	7365	6892	8076	9131	9300	8658	8000	7230	7005	6908	7277	7756

Table 2-3 shows the annual Federal system firm load obligations for OY2025 in Energy aMW.

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

Table 2-3 Federal System Annual Firm Obligations by Category OY2025

Customer Class	Energy (aMW)	Percent of Firm Energy
Load Following	3,914	50%
Tier One Block	570	7%
Slice	2,595	33%
DSI	11	0%
Contract Deliveries	772	10%
Total Firm Obligations	**7,861**	**100%**



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

Resources

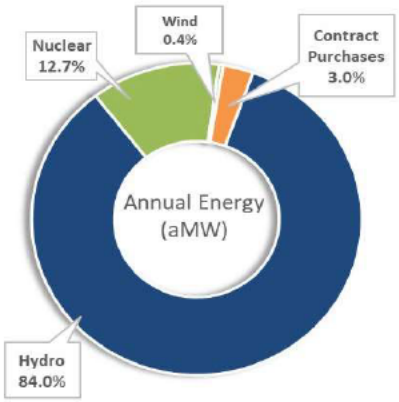
In the PNW, Bonneville is directed to market power from Federal hydroelectric projects and other resources acquired to meet firm power contractual obligations. By Statute, Bonneville does not own generating resources, but instead, Bonneville markets power from Federal resources and non-Federal generating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

Federal System Resource Types

Table 2-5 summarizes Bonneville's resources and contract purchases available to meet the Federal system load obligations. For OY2025, Federal system resources are forecast to produce 7,602 annual aMW of generation under Firm water conditions, after reserves and losses are included.

Table 2-5 Federal System Generations by Resource Type for OY2025 - Firm Water Conditions

Resource Type	Annual Energy (aMW)	Percent of Firm Energy
Hydro	6,589	84%
Nuclear	994	12.7%
Wind	33	0.4%
Contract Purchases	233	3%
Total Federal Resources	7,849	100%
Reserves & losses	-247	--
Total Net Resources	7,602	--



Federal system contract purchases

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

The Federal system resources are comprised of:

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

Table 2-6 Federal System Hydro Project Generation Forecasts by Streamflow Conditions[8] – OY2025

Project	Initial Service Date	Operator	Number of Units	Maximum Capacity d/ (MW)	High c/ Energy (aMW)	Median c/ Energy (aMW)	Firm Energy a/c/ (aMW)	
Regulated Hydro								
1. Albeni Falls	1955	USACE	3	50	21.5	25.8	25.3	
2. Dworshak	1974	USACE	3	465	304	193	155	
3. Hungry Horse	1952	USBR	4	310	129	94	88	
4. Libby	1975	USACE	5	605	280	236	193	
5. Grand Coulee / GCL Pumping	1941	USBR	27	6,684	3,063	2,306	1,872	
	1973		6	314				
6. Chief Joseph	1955	USACE	27	2,614	1,780	1,372	1,106	
7. Lower Granite	1975	USACE	6	930	295	190	139	Lower Snake River Projects
8. Little Goose	1970	USACE	6	930	312	207	155	
9. Lower Monumental	1969	USACE	6	930	297	203	147	
10. Ice Harbor	1961	USACE	6	693	260	190	144	
11. McNary	1953	USACE	14	1,120	626	545	451	Lower Columbia River Projects
12. John Day	1968	USACE	16	2,480	1,374	994	787	
13. The Dalles	1957	USACE	22	2,080	1,081	817	642	
14. Bonneville b/	1938	USACE	18	1,221	722	527	387	
15. Total Regulated Hydro Projects			**169**	**21,426**	**10,546**	**7,901**	**6,291**	
Independent Hydro Projects								
16. Anderson Ranch	1950	USBR	2	40	16	12	13	
17. Big Cliff	1954	USACE	1	21	14	11	11	
18. Black Canyon	1925	USBR	2	8.5	8	6	7	
19. Boise Diversion	1908	USBR	3	2.5	1	1	1	
20. Chandler	1956	USBR	2	12.2	9	7	6	
21. Cougar	1964	USACE	2	28	9	5	5	
22. Cowlitz Falls	1994	LCPD#1	2	70	33	29	29	
23. Detroit	1953	USACE	2	115	33	26	23	
24. Dexter	1955	USACE	1	17	10	8	8	
25. Foster	1968	USACE	2	23	10	8	8	
26. Green Peter	1967	USACE	2	92	22	16	16	
27. Green Springs	1960	USBR	1	18	7	7	7	
28. Hills Creek	1962	USACE	2	34	24	19	17	
29. Lookout Point	1954	USACE	3	138	17	15	20	
30. Lost Creek	1975	USACE	2	56	42	37	31	
31. Minidoka	1909	USBR	4	28	19	14	11	
32. Palisades	1957	USBR	4	177	100	92	77	
33. Roza	1958	USBR	1	14	9	8	6	
34. Total Independent Hydro Projects			**38**	**894**	**381**	**320**	**296**	
Small Non-Federally Owned Hydro Projects								
35. Dworshak/Clearwater Small Hydro	2000	ID DWR	1	5.4	2.6	2.6	2.6	
36. Rocky Brook	1985	MCPD#1	1	1.6	0.3	0.3	0.3	
37. Total Non-Federally Owned Hydro			**2**	**7**	**2.9**	**2.9**	**2.9**	
38. Total Hydro Generation *(line 15 + line 34 + line 37)*			**209**	**22,327**	**10,930**	**8,223**	**6,589**	

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

b/ Bonneville Dam generation totals include Bonneville Fishway

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

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

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

Table 2-7 Federal System Non-Hydro Project Generation Forecast and Contract Purchase – OY2025

	Project	Initial Service Date	Resource Type	Operator	Maximum Capacity [a/] (Peak MW)	Firm Energy (aMW)
	Non-Hydro Resources					
1	Columbia Generating Station	1984	Nuclear	ENW	1,178	994
2	Stateline Wind Project [b/]	2001	Wind	PPM, FLP	0	21 2
3	Klondike Phase III [c/]	2007	Wind	NW Wind Power	0	11 8
4	Fourmile Hill Geothermal [d/]	Not in Service	Geo.	Calpine	0	0
5	**Total Federal System Non-Hydro Resources**				**1,178**	**1,027**
	Contract Purchases					
6	Canadian Entitlement for Canada (non-Federal)				237	135
7	Canadian Imports				1	1
8	Pacific Southwest Imports				0	0
9	Intra-Regional Transfers In (Pacific Northwest Purchases)				175	69
10	Slice Transmission Loss Return				41	28
11	**Total Federal System Contract Purchases**				**454**	**233**
12	**Total Federal System Non-Hydro Resources and Contract Purchases**				**1,632**	**1,259**

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

Federal System Hydro Generation Variability

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

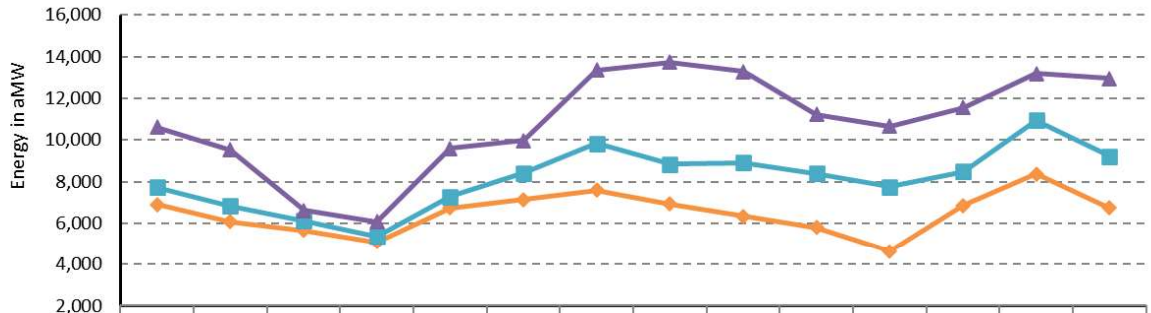
Table 2-8 Federal System Variability of Annual Hydro Generation by Streamflow Conditions – OY2025 – OY2034

Energy (aMW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Firm Water (p10)	6,589	6,536	6,614	6,544	6,628	6,633	6,633	6,642	6,623	6,688
Median Water (p50)	8,223	8,237	8,244	8,250	8,274	8,294	8,294	8,307	8,286	8,419
High Water (p90)	10,930	10,825	10,911	10,799	10,952	10,963	10,966	10,996	10,965	11,146

In OY2025, annual Federal system hydro energy generation is forecasted to be 6,589 aMW under Firm Water conditions. However, under the High Water conditions these same Federal system hydro

resources could generate as much as 10,930 aMW for OY2025. Table 2-9 displays the monthly variability of the Federal system hydro generation forecasted for OY2025, under the same three water conditions. Higher generation levels from January through March are largely due to drafting reservoirs for flood control and power production. The available water in those months depends greatly on annual rainfall and snowpack levels in the Columbia River Basin, and thus the generation exhibits large variability from year to year. Power production from April through July is variable based on the timing and amount of Columbia River Basin snowmelt runoff. Power production decreases through the end of summer and early fall as stream flows decline due to depleted snowpack and lower precipitation levels. Annual water volume variability generally has minimal impact on generation from the Federal system hydro resources in September and October. As observed from Table 2-9, hydro generation can vary by close to 7,000 aMW in a single month, almost double in this case March, depending on operations and availability of water.

Table 2-9 Federal System Monthly Hydro Generation Variability by Streamflow Conditions – OY2025

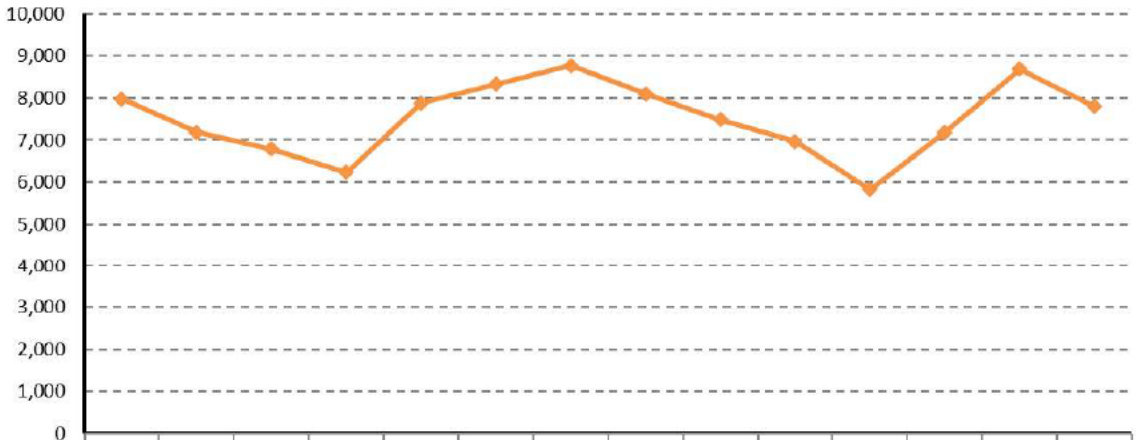


	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Firm Water (P10)	6,905	6,077	5,649	5,072	6,731	7,148	7,586	6,928	6,333	5,800	4,635	6,856	8,360	6,732
Median Water (P50)	7,727	6,835	6,121	5,357	7,284	8,416	9,840	8,830	8,904	8,395	7,748	8,484	10,931	9,220
High Water (P90)	10,620	9,522	6,620	6,070	9,601	9,962	13,355	13,732	13,291	11,224	10,652	11,567	13,185	12,956

Total Federal System Resources

Table 2-10 shows the monthly shape of forecasted total Federal system generation for energy (in aMW) for OY2025, under Firm water conditions. This includes generation from all Federal system hydro and non-hydro resources, as well as contract purchases. Overall, the Federal system maintains similar monthly shapes over the study period, with the highest generation forecasted in late fall and winter (Nov-March) and mid-summer periods.

Table 2-10 Federal System Monthly Generation for OY2025 under Firm Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	7982	7190	6790	6238	7885	8326	8768	8099	7486	6968	5828	7192	8692	7801

Key Results

Annual Energy

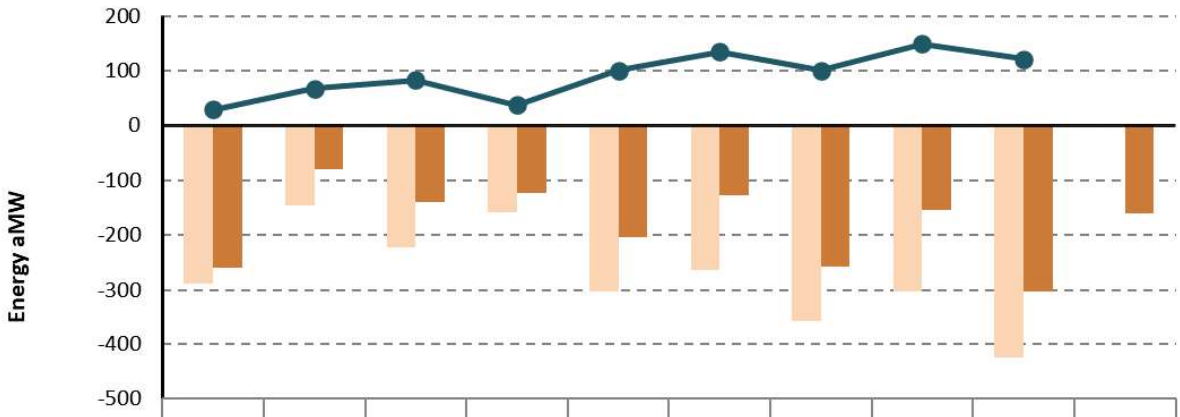
Table 2-11 shows that the Federal system is forecasted to have annual energy deficits throughout the study period. The individual components of the Federal system annual energy loads and resources are shown in Exhibit 4-1 for OY2025 through OY2034. The Federal system detailed monthly energy loads and resources are shown in Exhibit 4-2 for OY2025.

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

Energy (aMW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Surplus/ Deficits	-260	-79	-139	-122	-203	-128	-257	-153	-303	-161

Table 2-12 compares the 2024 White Book Federal system annual firm energy surplus/deficit results to those from the 2023 White Book. Compared with the previous White Book, the 2024 White Book shows a slight decrease in deficits annually throughout the studying period. These results reflect changes in both load obligations and Federal system generation.

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



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
2023 White Book	-289	-147	-223	-159	-303	-263	-357	-303	-424	
2024 White Book	-260	-79	-139	-122	-203	-128	-257	-153	-303	-161
Delta	29	67	83	37	100	134	100	149	121	

Federal System Annual Surplus/ Deficit

Table 2-13 graphically presents the annual firm energy surplus/deficits. Over the study period, the Federal system is forecasted to have a deficit in annual firm energy as high as 303 aMW near the end of the study period. Some differences in annual energy between odd and even years can be attributed to the biennial Columbia Generation Station (CGS) maintenance schedule[9].

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



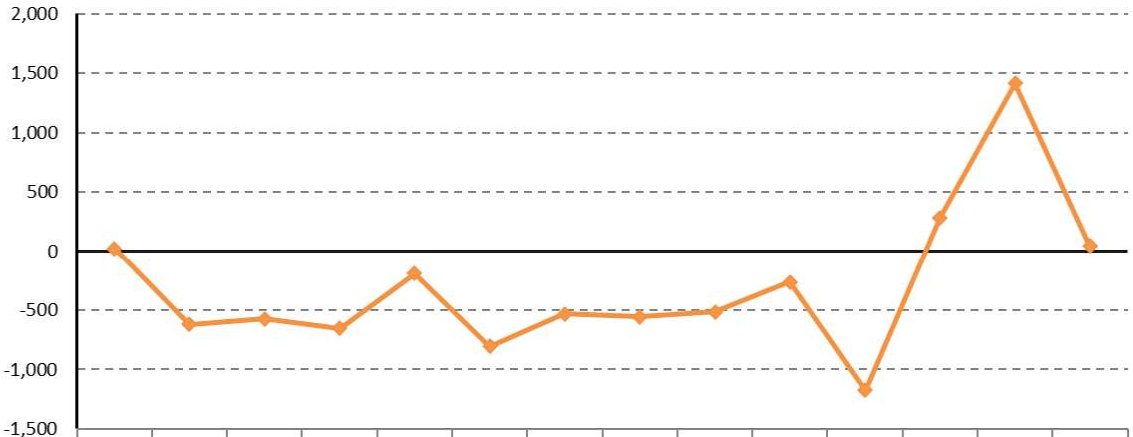
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy (aMW)	-260	-79	-139	-122	-203	-128	-257	-153	-303	-161

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

Federal System Monthly Surplus/ Deficit

Table 2-14 displays a graphic look at the Federal system monthly firm energy surplus/deficits for OY2025. Both forecasts maintain similar monthly shapes over the other Operating Years in this study period. With highest deficits comes in the second half of April and better positions come in May, June, and July.

Table 2-14 Federal System Monthly Surplus/ Deficits OY2025 under Firm Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	22	-620	-575	-654	-191	-805	-531	-559	-513	-262	-1177	284	1415	45

Conclusion

Under Firm water conditions, the Federal system shows annual firm energy deficits through the 2025-2034 study period. These annual energy deficits range from 79 aMW in OY2026 to as high as 303 aMW in OY2032. At a monthly resolution under Firm water conditions, the Federal system generally shows larger energy deficits across the winter and early spring periods until spring runoff starts, which then turns into surplus from May and to the early summer periods.

The Federal system surplus/deficit forecasts generally have a positive relationship with water conditions. Better water conditions generally yield more surplus overall. For example, the annual energy surplus can increase by over 4,000 aMW under better water conditions, while monthly surplus or deficit position can vary by close to 7,000 aMW within the same year.

The range of Federal system monthly surplus and deficit forecasts under all 30-water years is presented in Exhibit 4-3. Additional monthly and annual details for OY2025 through OY2034 are available upon request, a list of available data reports can be found in the Appendix. Reminder: Data Report requests can be received via email to WhiteBook@bpa.gov.

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SECTION 3: PACIFIC NORTHWEST REGIONAL ANALYSIS

The PNW Regional Analysis is an OY analysis that provides Bonneville's deterministic forecast of the PNW region's loads and resources over a 10-year period from OY 2025 through OY 2034. Firm load and resources forecasts are presented in energy based on regional retail loads, contract obligations, and resources. This White Book analysis assumes that generation from all regional uncommitted Independent Power Producer (IPP) projects is available to meet regional load. Regional retail loads, contract sales and purchases, and generating resources forecasts incorporate annual regional utility data submittals received by Bonneville.

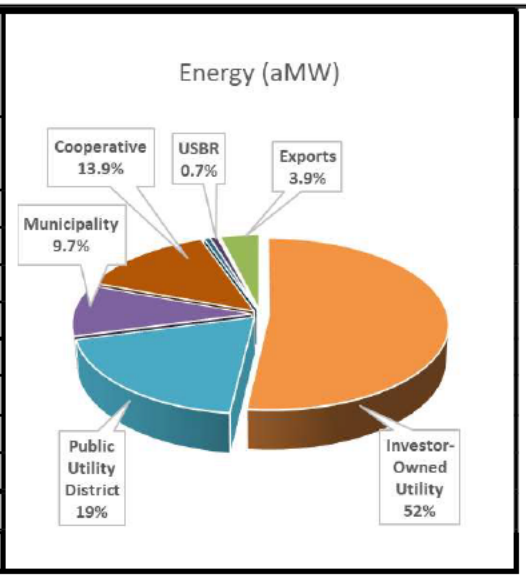
Regional Loads

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

Regional loads are comprised of roughly 96 percent retail loads and four percent exports. Table 3-1 shows the forecasted composition of PNW regional load for OY2025.

Table 3-1 PNW Region Firm Loads by Customer Class – OY2025

Customer Class	Energy (aMW)	Percent of Firm Energy
Investor-Owned Utility	13,566	52%
Public Utility District	4,963	19%
Municipality	2,545	9.7%
Cooperative	3,642	13.9%
Federal Agency	160	1%
USBR	186	0.7%
DSI	53	0.2%
Marketer	0	0.0%
Total Retail Load	**25,115**	**96%**
Exports	1,030	3.9%
Total Regional Load	**26,145**	**100%**



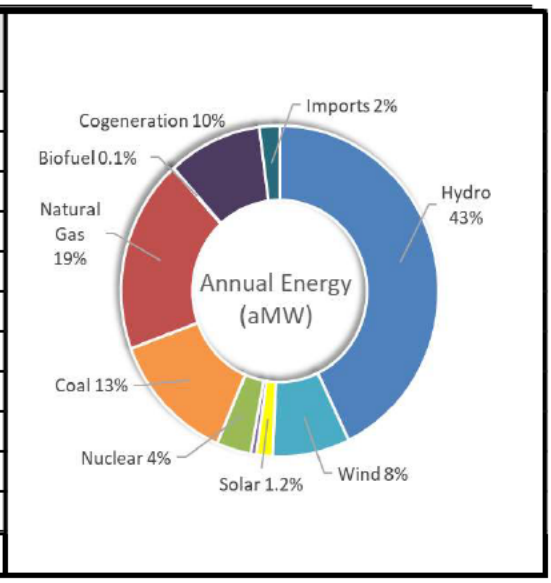
Regional Resources

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

Table 3-3 summarizes the resource generation available to meet PNW regional loads. The generation forecasts for these resources are provided by Bonneville models or the project owners. New regional generating projects are included when those resources begin operating or are under construction and have a scheduled on-line date; similarly, retiring resources are removed from the forecasts based on the data of the announced retirement date. Regional resource forecasts assume the retirement of the following coal projects over the study period: Centralia 2 (December 1, 2025) and Valmy 2 (January 1, 2026). Contract purchases are provided by the individual utility, follow specific contract provisions, and can have various delivery arrangements.

Table 3-3 PNW Regional Generations by Resource Type – OY2025 Firm Water Conditions

Project Type	Annual Energy (aMW)	Percent of Energy
Hydro	12,196	43%
Wind	2,238	8%
Solar	479	1.7%
Other Renewable	158	0.6%
Nuclear	994	3%
Coal	3,676	13%
Natural Gas	5,372	19%
Petroleum	0	0%
Biofuel	26	0.1%
Cogeneration	2,728	10%
Imports	591	2%
Total Regional Resources	**28,457**	**100%**



Regional Hydro Generation Variability

The generating capacity of regional hydroelectric projects depends upon the amount of water flowing through the facilities, the physical capacity of the facility, flow requirements pursuant to non-power requirements, and other operating limitations. Similarly to the Federal hydro resources, Bonneville utilizes the 30-year streamflow record and percentile of T1SFCO results for planning purposes. Again, three water conditions are presented here to represent the magnitude of hydro generation variability.

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

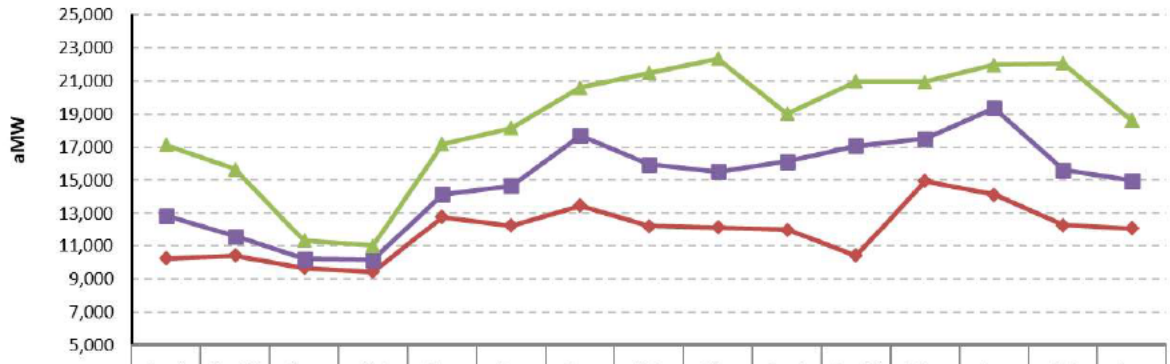
In OY2025, annual firm energy generation from regional hydro projects is forecasted to be 12,196 aMW under the firm water conditions, and this represents about 43% percent of the region's resources. However, the generating potential from regional hydro projects can vary annually by over 6,000 aMW between firm and high water conditions.

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

Energy (aMW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Firm Water (p10)	12,196	11,888	12,201	11,958	12,212	12,216	12,216	12,225	12,149	12,238
Median Water (p50)	14,729	14,807	14,727	14,820	14,756	14,786	14,786	14,800	14,819	14,932
High Water (p90)	18,817	18,751	18,854	18,708	18,885	18,893	18,922	18,957	18,929	19,110

Table 3-5 shows the monthly variability of regional hydro generation under the same three water conditions for OY2025. The increased level of generation in January through March period is largely due to drafting reservoirs for power production and flood control, which can vary widely due to rainfall and snowpack levels in the Columbia River Basin. Power production fluctuations in the second half of April through July are highly related to the timing and amount of Columbia River Basin snowmelt runoff. Power production decreases through the end of summer and early full as streamflow are reduced due to depleted snowpack and lower precipitation levels. Water variability does not have a substantial impact on regional hydro generation from September through November. Regional hydro generation capability can vary by as much as 10,000+ aMW between firm and high water conditions within the same month.

Table 3-5 PNW Regional Hydro Generation Monthly Variability by Streamflow Conditions - OY2025



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
Firm Water (P10)	10,268	10,424	9,680	9,468	12,772	12,264	13,459	12,220	12,157	12,010	10,436	14,953	14,121	12,294	12,081
Median Water (P50)	12,868	11,591	10,237	10,180	14,150	14,681	17,712	15,952	15,523	16,130	17,067	17,499	19,372	15,600	14,970
High Water (P90)	17,128	15,680	11,353	11,036	17,178	18,161	20,582	21,478	22,334	19,026	20,956	20,936	21,970	22,056	18,617

Uncommitted IPP Generation Delivered to the PNW Region

The PNW regional study includes uncommitted PNW IPP generation as regional resources. These resources, or the share of these resources, that are not committed to serving specific loads represent approximately 2,793 aMW of energy for OY2025. The inclusion of this uncommitted IPP generation is reasonable from the long-term planning perspective because the PNW Regional Analysis does not include any reliance on market purchases. However, PNW utilities may have to compete with other western markets to secure this generation to meet electricity demands. Table 3-6, next, details the region's total uncommitted IPP annual energy generation forecasts over the OY2025 through OY2034 study period.

Table 3-6 PNW Regional Annual Uncommitted IPP Generation

Regional Uncommitted IPP	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Annual Energy (aMW)	2,793	2,790	2,629	2,546	2,586	2,592	2,592	2,592	2,591	2,601

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

Table 3-7 PNW Regional Uncommitted Independent Power Producer Projects – OY2025 Firm Water Conditions

Project	Fuel Type	Energy (aMW)	Peak (MW)
Airport Solar	Solar	13	0
Centralia Complex [a/b/]	Coal	260	290
Condon Wind	Wind	12	0
Cosmopolis Specialty Fibres	Wood Waste	14	14
Hermiston Power Project	Wood Waste	567	630
International Paper Energy Center	Wood Waste	17	22
Juniper Canyon Wind	Wind	36	0
Kittitas Valley Wind	Wind	24	0
Klamath Generation Facility	Natural Gas	436	484
Klamath Generation Peakings (CT)	Natural Gas	90	100
Klondike Wind 1	Wind	6	0
Klondike Wind 3	Wind	23	0
Klondike Wind 3a	Wind	18	0
Leaning Juniper Wind	Wind	47	0
Longview Fibre Paper & Packaging	Wood Waste	35	35
Nippon Paper Cogen (Port Angeles)	Wood Waste	0	6
Pelton	Hydro	14	41
Priest Rapids	Hydro	85	154
Rock Island	Hydro	168	154
Rocky Reach	Hydro	155	339
Round Butte	Hydro	31	99
Satsop Combustion Turbine Project	Natural Gas	584	650
SDS Lumber	Wood Waste	1	1
Smith Creek (Idaho)	Hydro	7	0

Project	Fuel Type	Energy (aMW)	Peak (MW)
Stateline Wind	Wind	8	0
Stimson Lumber (Plummer)	Wood Waste	44	7
Tacoma Biomass (WestRock)	Wood Waste	0	0
Tieton Dam (Yakima)	Hydro	0	0
Vansycle Wind	Wind	23	0
Wanapum	Hydro	25	60
Weyerhaeuser Longview	Wood Waste	35	44
Willow Creek Wind	Wind	16	0
Total Uncommitted IPP Generation		**2,793**	**3,129**

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

Key Results

Annual Energy

Table 3-8 shows annual energy surpluses for the PNW region in the first two operating years, then increasingly more deficit going forward to outyears. This study assumes that 100 percent of the PNW region's uncommitted IPP generation (2,793 aMW in OY2025) is available to serve regional loads. The individual components of the PNW regional annual energy loads and resources for OY2025 through OY2034 are shown in Exhibit 5-1, and OY2025 monthly PNW regional details are shown in Exhibit 5-2. Other details of each component for OY2025 through OY2034 are available upon request via email at WhiteBook@bpa.gov.

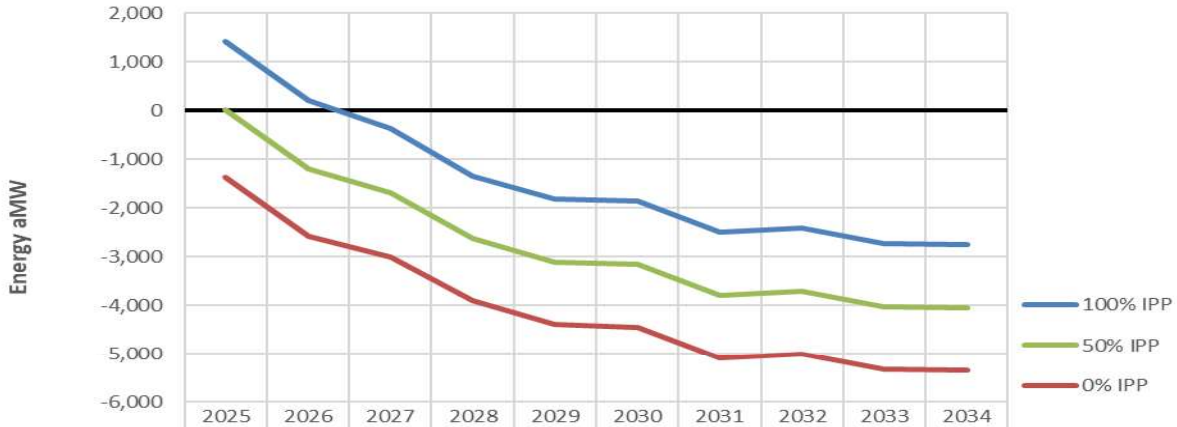
Table 3-8 PNW Regional Annual Energy Surplus/ Deficit - Firm Water Conditions

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

Energy (aMW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Surplus/ Deficit	1,426	207	-370	-1,352	-1,808	-1,861	-2,492	-2,407	-2,725	-2,738

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

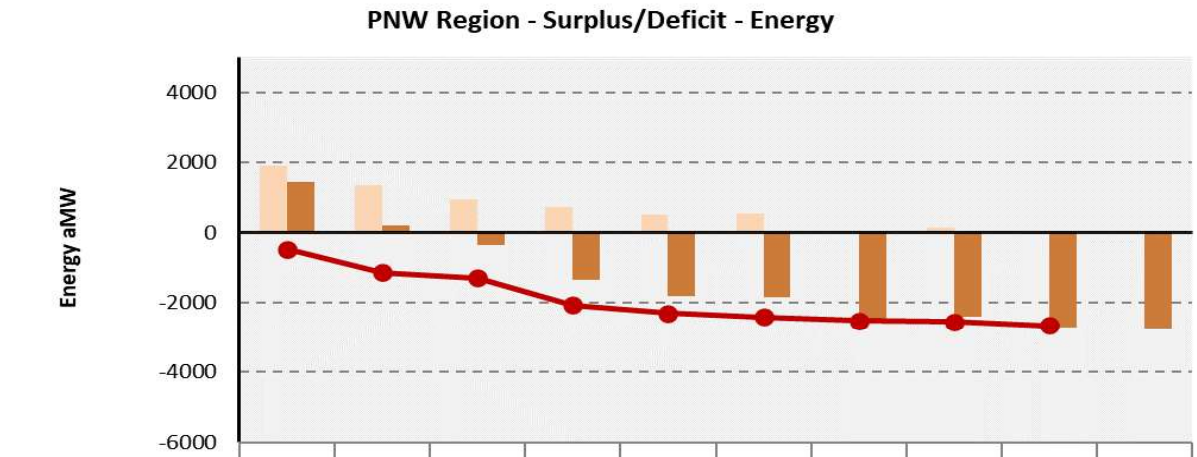
Table 3-9 PNW Regional Annual Energy Surplus/ Deficit by Uncommitted IPP Generation %



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
100% IPP	1,426	207	-370	-1,352	-1,808	-1,861	-2,492	-2,407	-2,725	-2,738
50% IPP	29	-1,189	-1,684	-2,625	-3,101	-3,158	-3,788	-3,703	-4,020	-4,038
0% IPP	-1,367	-2,584	-2,999	-3,898	-4,393	-4,454	-5,085	-4,999	-5,316	-5,339

Table 3-10 compares the 2024 White Book PNW regional annual firm energy surplus/ deficit forecasts to that of the 2023 White Book. Immediately, the comparison results show significant differences where OY2025 is less surplus in this study, and the difference gets more pronounced beginning in OY2026 and extends out all outyears where surplus became large deficits. This change is mainly driven by an increase in the PNW Regional Retail Load, more specifically in the new large industrial loads.

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



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
2023 White Book	1905	1357	932	728	509	553	40	144	-61	
2024 White Book	1426	207	-370	-1352	-1808	-1861	-2492	-2407	-2725	-2738
Delta	-479	-1150	-1302	-2080	-2317	-2414	-2533	-2551	-2664	

Regional Annual Surplus/ Deficit

Table 3-11 graphically presents the annual firm energy surplus/ deficit forecasts for the PNW region. These forecasts assume 100 percent availability of the PNW uncommitted IPP generation to serve the region's loads. The regional annual energy surplus/ deficit declines over the 10-year study period.

Table 3-11 PNW Regional Annual Surplus/ Deficit – Firm Water Conditions

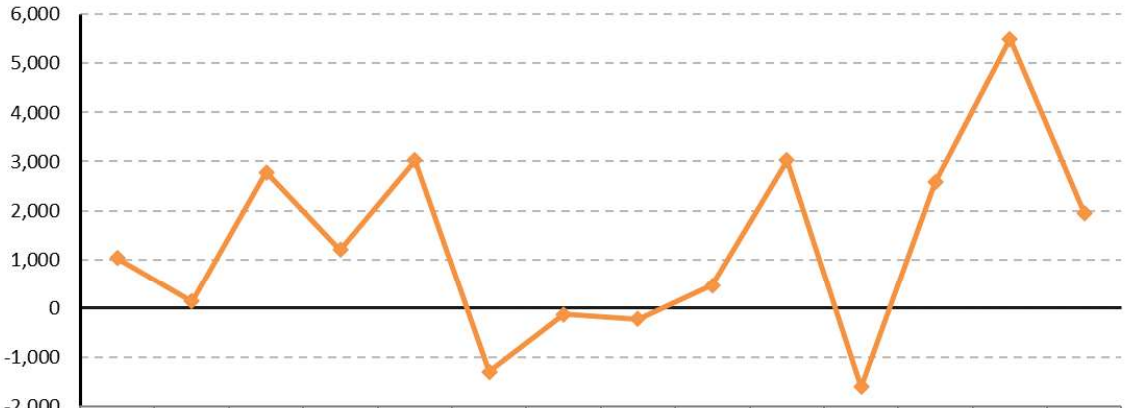


	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy (aMW)	1,426	207	-370	-1,352	-1,808	-1,861	-2,492	-2,407	-2,725	-2,738

Regional Monthly Surplus/ Deficit

Table 3-12 shows the monthly energy surplus/ deficit forecast for OY2025. Again, these forecasts assume 100 percent of uncommitted IPP generation serving the region. This monthly view shows how both metrics follow a similar monthly shape with most surplus months in late spring to beginning of summer, and most deficits around the second half of April, before the runoff begins historically and as fish operations begin.

Table 3-12 PNW Regional Monthly Surplus/ Deficit – OY2025 Firm Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	1,032	143	2,784	1,203	3,027	-1,300	-122	-224	464	3,026	-1,600	2,584	5,496	1,953

Conclusion

The PNW region is projected to have annual firm energy surpluses in the first two operating years then surpluses sharply declined and quickly becoming deficits, then continued with larger deficits going into the outyears, under the assumption of 100 percent of the PNW region's uncommitted IPP generation available to serve the region's load. Additionally, due to the fact that 100 percent of the uncommitted IPP generation is assumed to be available to serve the region's load, with its uncommitted nature, the supply of power within the region can change dramatically and quickly if those resources were to be used to serve loads outside of the region or retire early or unexpectedly.

Detailed surplus/deficit forecasts for all 30-historical water conditions are presented in Exhibit 5-3; monthly and annual details for OY2025 through OY2034 are available upon request with the itemized list located in the Appendix.

The regional energy and capacity deficits identified in this study may be mitigated through resource options discussed in the NWPCC's Power Plan publications, NWPCC is currently working on updating their 2021 Northwest Power Plan[10] and it is updated roughly every 5-year. Bonneville provides this PNW regional planning analysis for informational purposes only.

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

SECTION 4: FEDERAL SYSTEM ANALYSIS EXHIBITS

Exhibit 4-1: Annual Energy – Federal System Surplus/ Deficit:

Operating Years 2025 – 2034, Firm Water Conditions

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Loads and Resources - Federal System Percentile
Operating Year: 2025 to 2034 Percentile: 10
White Book 2024 Report Date: **6/7/2024**

S251-WB-20240606-131030

	Energy-aMW	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Firm Obligations										
1	**Load Following**	3914	3981	4024	4058	4096	4136	4160	4173	4196	4214
2	Preference Customers	3578	3639	3680	3712	3747	3786	3809	3823	3844	3862
3	Federal Agencies	150	156	158	160	163	164	165	165	165	166
4	USBR	186	186	186	185	186	186	186	185	186	186
5	Federal Diversity	0	0	0	0	0	0	0	0	0	0
6	**Tier 1 Block**	570	569	570	568	569	568	569	567	568	567
7	Tier 1 Block	570	569	570	568	569	568	569	567	568	567
8	**Slice**	2595	2591	2591	2586	2590	2604	2590	2602	2591	2615
9	Slice Block	1227	1210	1221	1208	1219	1207	1217	1204	1220	1208
10	Slice Output from T1 System	1368	1381	1370	1378	1371	1396	1373	1398	1371	1407
11	**Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
12	Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
13	**Contract Deliveries**	772	591	490	478	479	475	473	473	473	473
14	Exports	477	468	468	468	468	464	464	464	464	464
15	Intra-Regional Transfers (Out)	295	123	22.4	10.7	10.7	10.7	9.44	9.44	9.44	9.44
16	**Total Firm Obligations**	**7861**	**7743**	**7686**	**7702**	**7745**	**7793**	**7803**	**7827**	**7839**	**7880**
	Net Resources										
17	**Hydro**	6589	6536	6614	6544	6628	6633	6633	6642	6623	6688
18	Regulated Hydro - Net	6291	6258	6313	6264	6342	6349	6349	6361	6371	6433
19	Independent Hydro - Net	296	275	298	277	283	281	281	278	249	252
20	Small Hydro - Net	2.88	2.88	2.88	2.88	2.88	2.88	2.88	2.87	2.88	2.88
21	**Non-Hydro Renewable**	33.0	33.0	19.8	1.90	0	0	0	0	0	0
22	Wind - Net	33.0	33.0	19.8	1.90	0	0	0	0	0	0
23	Other - Net	0	0	0	0	0	0	0	0	0	0
24	**Thermal**	994	1116	994	1116	994	1116	994	1116	994	1116
25	Nuclear - Net	994	1116	994	1116	994	1116	994	1116	994	1116
26	**Contract Purchases**	233	227	164	164	164	165	164	165	164	165
27	Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
28	Intra-Regional Transfers (In)	68.6	63.0	0	0	0	0	0	0	0	0
29	Non-Federal CER	135	135	135	135	135	135	135	135	135	135
30	Slice Transmission Loss Return	28.0	28.2	28.0	28.2	28.0	28.6	28.1	28.6	28.0	28.8
31	**Reserves & Losses**	-247	-249	-245	-246	-245	-249	-245	-249	-245	-251
32	Operating Reserves	0	0	0	0	0	0	0	0	0	0
33	Balancing Reserves	0	0	0	0	0	0	0	0	0	0
34	Transmission Losses	-247	-249	-245	-246	-245	-249	-245	-249	-245	-251
35	**Total Net Resources**	**7602**	**7664**	**7546**	**7580**	**7541**	**7665**	**7546**	**7673**	**7536**	**7719**
36	**Total Surplus/Deficit**	**-260**	**-79.3**	**-139**	**-122**	**-203**	**-128**	**-257**	**-153**	**-303**	**-161**

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Exhibit 4-2: Monthly Energy – Federal System Surplus/ Deficit: Operating Year 2025, Firm Water Conditions

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Loads and Resources - Federal System Percentile
Operating Year: 2025 Percentile: 10
White Book 2024 Report Date: **6/11/2024**
S251-WB-20240606-131030

	Energy-aMW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
	Firm Obligations															
1	**Load Following**	3843	3845	3356	3422	3725	4520	4532	4186	3809	3716	3716	3679	3939	4231	3914
2	Preference Customers	3369	3373	2936	3163	3559	4336	4348	3988	3592	3344	3344	3209	3436	3659	3578
3	Federal Agencies	136	136	125	138	159	181	176	184	159	141	141	129	127	142	150
4	USBR	338	336	295	121	7.27	3.43	7.16	13.7	57.7	231	231	342	376	429	186
5	Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	**Tier 1 Block**	379	379	636	522	877	865	953	898	853	410	410	137	9.50	327	570
7	Tier 1 Block	379	379	636	522	877	865	953	898	853	410	410	137	9.50	327	570
8	**Slice**	2506	2349	2285	2244	2768	3040	3108	2866	2635	2401	2176	2389	2626	2473	2595
9	Slice Block	1113	1113	1092	1128	1310	1502	1489	1373	1265	1164	1164	1117	1069	1106	1227
10	Slice Output from T1 System	1393	1235	1192	1117	1458	1537	1620	1493	1371	1237	1013	1272	1557	1366	1368
11	**Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11
12	Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11
13	**Contract Deliveries**	1222	1226	1078	693	695	694	696	696	692	693	693	692	692	714	772
14	Exports	644	649	508	454	454	454	454	454	454	454	454	454	454	477	477
15	Intra-Regional Transfers (Out)	578	578	570	238	241	240	241	242	237	238	238	237	237	237	295
16	**Total Firm Obligations**	**7961**	**7810**	**7365**	**6892**	**8076**	**9131**	**9300**	**8658**	**8000**	**7230**	**7005**	**6908**	**7277**	**7756**	**7861**
	Net Resources															
17	**Hydro**	6905	6077	5649	5072	6731	7148	7586	6928	6333	5800	4635	6856	8360	6732	6589
18	Regulated Hydro - Net	6558	5744	5356	4805	6462	6981	7295	6685	6130	5522	4424	6438	7889	6358	6291
19	Independent Hydro - Net	344	330	291	265	267	164	288	241	201	274	208	416	469	372	296
20	Small Hydro - Net	2.63	2.63	2.63	2.67	2.84	3.19	3.21	3.05	3.10	3.09	3.09	2.83	2.72	2.63	2.9
21	**Non-Hydro Renewable**	22.6	33.8	31 5	25.3	36 2	27.6	14.8	24.4	28.1	50.2	42.3	45.2	44.7	43.7	33
22	Wind - Net	22.6	33.8	31.5	25.3	36.2	27.6	14.8	24.4	28.1	50.2	42.3	45.2	44.7	43.7	33
23	Other - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	**Thermal**	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	360	409	1116	994
25	Nuclear - Net	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	360	409	1116	994
26	**Contract Purchases**	202	200	213	226	256	303	335	292	251	228	223	164	165	166	233
27	Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.0
28	Intra-Regional Transfers (In)	34.7	35.0	57.0	64.5	88.9	138	164	125	89.0	64.4	64.4	0	0	0	69
29	Non-Federal CER	137	138	131	138	137	132	137	135	133	137	137	137	132	137	135
30	Slice Transmission Loss Return	29.0	25.7	24.2	22.7	29.6	31 2	32.9	30.3	27.9	25.1	20.6	25.9	32.4	28.4	28
31	**Reserves & Losses**	-262	-236	-220	-202	-255	-269	-283	-262	-242	-225	-189	-234	-287	-257	-247
32	Operating Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	Balancing Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Transmission Losses	-262	-236	-220	-202	-255	-269	-283	-262	-242	-225	-189	-234	-287	-257	-247
35	**Total Net Resources**	**7982**	**7190**	**6790**	**6238**	**7885**	**8326**	**8768**	**8099**	**7486**	**6968**	**5828**	**7192**	**8692**	**7801**	**7602**
36	**Total Surplus/Deficit**	**22**	**-620**	**-575**	**-654**	**-191**	**-805**	**-531**	**-559**	**-513**	**-262**	**-1,177**	**284**	**1,415**	**45**	**-260**

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Exhibit 4-3: 30-Water Year Conditions Monthly Energy – Federal System Surplus/ Deficit: Operating Year 2025

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Federal Report Surplus Deficit By Water Year

Operating Year 2025

White Book 2024 Report Date: **6/12/2024**

S251-WB-20240606-131030

Energy-aMW - Surplus Deficit	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
1 1989 Federal Report Surplus Deficit	165	720	-595	-750	-89.4	-61.7	-379	-1582	1010	1762	1538	1897	1096	579	281
2 1990 Federal Report Surplus Deficit	263	-323	-322	-375	363	1250	1386	2959	1050	1757	1832	1135	4061	3543	1387
3 1991 Federal Report Surplus Deficit	2448	1783	10.3	-557	2156	1325	2885	3853	2345	2527	1264	1529	3433	3947	2065
4 1992 Federal Report Surplus Deficit	2923	1505	-384	-446	184	-1251	-345	69.6	-513	361	-1177	662	2044	-262	127
5 1993 Federal Report Surplus Deficit	295	-354	-345	-657	5.21	-799	-934	-1812	45.9	-175	-1243	2052	1852	1905	60.5
6 1994 Federal Report Surplus Deficit	880	59.0	3.11	-452	122	-749	-1008	-386	-550	-473	161	284	1945	367	-12.4
7 1995 Federal Report Surplus Deficit	249	-600	-207	-532	-87.3	-438	8.22	926	2561	248	-192	1078	3358	2160	719
8 1996 Federal Report Surplus Deficit	1481	373	184	658	2864	5213	5859	5939	5958	2553	3179	2580	5048	4715	3555
9 1997 Federal Report Surplus Deficit	2666	2075	290	-97.3	899	1390	5700	6078	4929	4079	4884	5676	6092	4905	3544
10 1998 Federal Report Surplus Deficit	3102	2699	1029	2053	1696	343	1227	2280	1102	105	-4.86	4008	3881	2471	1919
11 1999 Federal Report Surplus Deficit	2786	1240	6.38	-350	-280	763	3971	3461	4916	2123	2643	1608	4099	5309	2321
12 2000 Federal Report Surplus Deficit	4177	3353	271	123	2224	1826	2389	2447	2242	2097	2603	1802	1415	2016	1904
13 2001 Federal Report Surplus Deficit	2052	-461	-252	-415	-179	-944	-867	-204	-627	-1133	-1752	-445	325	-79.1	-366
14 2002 Federal Report Surplus Deficit	557	-509	-598	-771	-385	-172	-435	-84.5	-39.2	1704	1407	1146	4371	3370	664
15 2003 Federal Report Surplus Deficit	519	-200	-168	-422	241	-805	-531	207	1592	483	1011	750	3312	321	445
16 2004 Federal Report Surplus Deficit	-362	-673	-528	-584	648	-274	-148	-559	-2.77	302	522	573	2791	685	207
17 2005 Federal Report Surplus Deficit	-44.5	188	125	226	680	554	960	2200	293	-592	-204	601	1808	1387	699
18 2006 Federal Report Surplus Deficit	544	-449	-317	-654	705	349	2848	3649	1492	3081	1861	3573	3579	1703	1603
19 2007 Federal Report Surplus Deficit	657	-344	-435	-477	294	394	2250	1216	3538	3638	888	1390	1993	1514	1174
20 2008 Federal Report Surplus Deficit	351	-578	-575	-585	415	-9.96	97.8	169	395	564	-827	2244	4735	3026	806
21 2009 Federal Report Surplus Deficit	1255	1256	-18.7	-383	371	-556	1621	457	-206	1863	1249	1324	1745	1098	688
22 2010 Federal Report Surplus Deficit	21.7	-873	-378	-389	-90.5	-972	-313	-625	-775	-262	-1313	-25.7	3907	1988	91.3
23 2011 Federal Report Surplus Deficit	664	-145	-21.6	-528	-191	896	4049	4813	2755	3971	1251	2374	6134	6497	2454
24 2012 Federal Report Surplus Deficit	3584	1513	17.1	0.97	155	212	2372	2598	2441	4420	4363	2745	5182	5513	2342
25 2013 Federal Report Surplus Deficit	2864	2070	-93.9	-377	1352	1961	1074	842	334	3563	1801	1949	3797	2054	1503
26 2014 Federal Report Surplus Deficit	1212	-28.0	72.3	-248	111	-40.0	1675	32.9	3464	2974	1486	1986	3422	3352	1396
27 2015 Federal Report Surplus Deficit	1262	21.4	17.5	-481	1229	1317	2831	3756	4315	1596	-324	-201	834	-364	1194
28 2016 Federal Report Surplus Deficit	105	-664	-666	-432	155	-194	47.7	102	3280	3495	3518	1554	1835	45.4	745
29 2017 Federal Report Surplus Deficit	16.1	-620	-268	-108	2049	948	3132	3986	6193	5323	4112	3960	5272	2052	2620
30 2018 Federal Report Surplus Deficit	1872	565	-292	-523	-602	184	3432	4752	2782	2508	1859	4957	3734	1141	1896

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SECTION 5: PACIFIC NORTHWEST REGIONAL ANALYSIS EXHIBITS

Exhibit 5-1: Annual Energy – PNW Regional Surplus/ Deficit: Operating Years 2025 – 2034, Firm Water Conditions

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Loads and Resources - Pacific Northwest Region Percentile
Operating Year: 2025 to 2034 Percentile: 10
White Book 2024 Report Date: **6/12/2024**
S251-WB-20240606-131030

	Energy-aMW	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Regional Loads										
1	**Retail Loads**	25115	25734	26358	27131	27747	27984	28140	28242	28451	28587
2	Federal Agency	160	166	168	170	172	173	173	173	174	174
3	USBR	186	186	186	185	186	186	186	185	186	186
4	Cooperative	3642	4156	4666	5329	5791	5912	5960	5979	6055	6100
5	Municipality	2545	2546	2545	2547	2551	2555	2562	2558	2567	2571
6	Public Utility District	4963	5011	5068	5116	5181	5242	5289	5324	5374	5406
7	Investor-Owned Utility	13566	13617	13673	13730	13813	13864	13917	13968	14042	14096
8	Direct-Service Industry	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3
9	Federal Diversity	0	0	0	0	0	0	0	0	0	0
10	**Exports**	1030	1021	1021	1020	1019	1013	765	670	670	670
11	Canada	468	468	468	468	468	464	464	464	464	464
12	East Continental Divide	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
13	Pacific Southwest	561	552	552	552	550	548	300	205	205	205
14	**Total Regional Loads**	**26145**	**26755**	**27379**	**28151**	**28765**	**28997**	**28905**	**28911**	**29121**	**29256**
	Regional Resources										
15	**Hydro**	12196	11888	12201	11958	12212	12216	12216	12225	12149	12238
16	Regulated Hydro - Net	11030	10763	11026	10832	11029	11034	11034	11044	10974	11076
17	Independent Hydro - Net	922	881	931	883	939	939	939	938	932	919
18	Small Hydro - Net	244	244	244	243	244	244	244	243	244	244
19	**Non-Hydro Renewable**	2875	2902	2902	2901	2903	2902	2886	2897	2902	2902
20	Wind - Net	2238	2238	2238	2236	2238	2238	2222	2233	2238	2238
21	Solar - Net	479	508	508	507	508	508	508	507	508	508
22	Other - Net	158	157	157	158	158	157	157	157	157	157
23	**Thermal**	12796	12444	12176	12198	12103	12280	12029	12198	12158	12195
24	Nuclear - Net	994	1116	994	1116	994	1116	994	1116	994	1116
25	Coal - Net	3676	3201	3049	2955	2981	3034	2948	2962	3034	2948
26	Natural Gas - Net	5372	5371	5371	5373	5372	5368	5371	5372	5371	5371
27	Petroleum - Net	0	0	0	0	0	0	0	0	0	0
28	Biofuel - Net	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5
29	Cogeneration - Net	2728	2730	2737	2729	2730	2737	2691	2722	2734	2734
30	**Imports**	591	595	599	603	607	610	130	36.5	36.4	36.4
31	Canada	38.8	38.8	38.8	38.8	38.8	38.8	36.7	36.5	36.4	36.4
32	Inland Southwest	506	509	513	517	521	525	93.6	0	0	0
33	Pacific Southwest	47.1	47.1	47.1	47.1	47.1	47.1	0	0	0	0
34	**Reserves & Losses**	-887	-867	-868	-861	-867	-873	-849	-852	-849	-853
35	Operating Reserves	0	0	0	0	0	0	0	0	0	0
36	Balancing Reserves	0	0	0	0	0	0	0	0	0	0
37	Transmission Losses	-887	-867	-868	-861	-867	-873	-849	-852	-849	-853
38	**Total Regional Resources**	**27571**	**26962**	**27009**	**26799**	**26958**	**27136**	**26412**	**26504**	**26396**	**26518**
39	**Total Surplus/Deficit**	**1426**	**207**	**-370**	**-1352**	**-1808**	**-1861**	**-2492**	**-2407**	**-2725**	**-2738**

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Exhibit 5-2: Monthly Energy – PNW Regional Surplus/ Deficit: Operating Year 2025, Firm Water Conditions

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Loads and Resources - Pacific Northwest Region Percentile

Operating Year: 2025 Percentile: 10

White Book 2024 Report Date: **6/11/2024**

S251-WB-20240606-131030

Energy-aMW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
Regional Loads															
1 **Retail Loads**	24827	24844	22311	23053	24979	28759	28248	27123	24977	23475	23475	23070	24606	25969	25115
2 Federal Agency	147	148	136	150	167	189	184	192	167	153	153	140	139	154	160
3 USBR	338	336	295	121	7 27	3.43	7.16	13.7	57.7	231	231	342	376	429	186
4 Cooperative	3165	3167	2881	3487	3656	4087	4070	3886	3659	3583	3583	3573	3762	3894	3642
5 Municipality	2281	2284	2200	2382	2676	3096	3106	2946	2716	2448	2448	2220	2202	2290	2545
6 Public Utility District	4664	4668	4354	4498	5122	5857	5871	5582	5085	4730	4730	4474	4574	4765	4963
7 Investor-Owned Utility	14179	14189	12392	12362	13297	15473	14956	14449	13238	12277	12277	12269	13501	14385	13566
8 Direct-Service Industry	52.2	52.2	52.9	53.8	54.2	53 9	54.3	54.0	53.5	53.9	53.9	52.4	52.1	52.1	53
9 Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 **Exports**	1186	1361	1167	846	1003	873	679	825	880	1215	1102	1147	1192	1306	1030
11 Canada	589	593	454	454	454	454	454	454	454	454	454	454	454	477	468
12 East Continental Divide	1.00	1 00	1.00	1.00	1 00	1.00	1.00	1 00	1.00	1 00	1.00	1.00	1 00	1.00	1.0
13 Pacific Southwest	596	767	712	390	548	417	223	369	425	760	647	692	737	829	561
14 **Total Regional Loads**	**26013**	**26205**	**23478**	**23898**	**25982**	**29631**	**28927**	**27948**	**25857**	**24690**	**24578**	**24217**	**25798**	**27275**	**26145**
Regional Resources															
15 **Hydro**	11631	10145	10313	9577	12623	12376	13860	12109	11280	12153	9151	13884	16585	12258	12196
16 Regulated Hydro - Net	10309	8944	9277	8644	11686	11528	12810	11121	10273	11035	8014	12282	14797	10860	11030
17 Independent Hydro - Net	997	878	791	771	809	723	926	857	845	838	855	1200	1366	992	922
18 Small Hydro - Net	325	323	244	163	128	126	124	132	162	280	282	403	422	405	244
19 **Non-Hydro Renewable**	2348	3106	2800	2292	2868	2222	1431	2134	2521	4083	3553	3870	3935	3855	2875
20 Wind - Net	1592	2338	2160	1742	2428	1869	1046	1661	1895	3311	2799	3023	3046	2951	2238
21 Solar - Net	597	608	483	390	281	194	237	314	467	616	596	687	755	724	479
22 Other - Net	159	159	157	160	159	159	148	158	158	157	157	160	134	181	158
23 **Thermal**	13425	13433	13454	13530	13750	13843	13803	13738	12829	11885	10532	9375	11207	13423	12796
24 Nuclear - Net	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	360	409	1116	994
25 Coal - Net	3821	3822	3825	3826	3824	3828	3828	3827	3580	2989	2792	3202	3842	3824	3676
26 Natural Gas - Net	5585	5592	5654	5716	5851	5921	5914	5853	5804	5484	4427	3381	4262	5587	5372
27 Petroleum - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28 Biofuel - Net	23.6	23.6	25.4	26.7	27.0	24.6	24.3	24.4	27.0	25.4	25.4	27.2	25.0	25.8	26
29 Cogeneration - Net	2879	2879	2833	2844	2933	2954	2920	2918	2301	2271	2171	2404	2669	2869	2728
30 **Imports**	586	586	514	484	671	773	608	608	511	458	458	506	663	715	591
31 Canada	20.8	20.8	15.8	22.0	38.9	49.3	62.3	70.8	62.7	30.2	30.2	28.9	38.6	27 0	39
32 Inland Sou hwest	565	565	498	462	452	488	458	473	448	428	428	477	624	688	506
33 Pacific Southwest	0	0	0	0	181	235	87.4	63.3	0	0	0	0	0	0	47
34 **Reserves & Losses**	-946	-922	-818	-782	-903	-882	-897	-863	-820	-863	-716	-835	-1095	-1022	-887
35 Operating Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36 Balancing Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37 Transmission Losses	-946	-922	-818	-782	-903	-882	-897	-863	-820	-863	-716	-835	-1095	-1022	-887
38 **Total Regional Resources**	**27045**	**26347**	**26263**	**25102**	**29009**	**28331**	**28805**	**27725**	**26321**	**27716**	**22978**	**26801**	**31294**	**29229**	**27571**
39 **Total Surplus/Deficit**	**1,032**	**143**	**2,784**	**1,203**	**3,027**	**-1,300**	**-122**	**-224**	**464**	**3,026**	**-1,600**	**2,584**	**5,496**	**1,953**	**1426**

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Exhibit 5-3: 30-Water Year Conditions Monthly Energy – PNW Regional Surplus/ Deficit: Operating Year 2025

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Regional Report Surplus Deficit By Water Year
Operating Year 2025
White Book 2024 Report Date: **6/12/2024**
S251-WB-20240606-131030

	Energy-aMW - Surplus Deficit	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
1	1989 Regional Report Surplus Deficit	1,113	2,481	2,207	958	3,232	475	-161	-1,949	3,336	6,643	5,604	5,716	4,685	3,262	2,494
2	1990 Regional Report Surplus Deficit	1,382	889	2,852	1,661	4,402	3,609	4,191	6,433	3,745	6,695	5,442	4,145	9,646	8,534	4,676
3	1991 Regional Report Surplus Deficit	5,236	4,663	3,377	1,625	8,218	3,391	5,888	8,450	6,127	7,974	4,018	5,115	8,629	9,858	5,941
4	1992 Regional Report Surplus Deficit	6,293	4,361	2,848	1,440	3,332	-1,485	-44	1,392	464	3,994	-1,600	2,369	4,504	933	1,846
5	1993 Regional Report Surplus Deficit	816	347	2,241	962	2,846	-1,354	-1,664	-2,176	1,621	2,898	-1,078	6,179	5,591	5,591	1,797
6	1994 Regional Report Surplus Deficit	2,908	1,474	3,402	1,523	2,967	-1,013	-1,483	59	816	1,901	2,329	2,584	5,060	2,301	1,704
7	1995 Regional Report Surplus Deficit	919	90	2,777	1,275	2,831	153	790	3,227	6,636	3,218	684	4,585	8,909	6,034	3,296
8	1996 Regional Report Surplus Deficit	4,135	2,043	3,693	3,845	9,510	10,638	11,355	12,937	12,891	8,755	8,925	7,319	11,370	10,834	8,829
9	1997 Regional Report Surplus Deficit	5,941	5,338	4,071	2,483	5,022	3,643	11,142	12,581	11,329	11,554	10,839	12,084	13,252	11,634	8,643
10	1998 Regional Report Surplus Deficit	7,189	6,676	5,977	7,313	6,865	1,839	3,538	5,466	4,128	3,772	1,924	9,320	9,824	6,841	5,906
11	1999 Regional Report Surplus Deficit	6,008	3,713	3,628	1,824	3,111	2,724	8,168	7,702	10,925	7,691	6,901	5,896	10,596	12,529	6,597
12	2000 Regional Report Surplus Deficit	9,000	7,826	4,056	2,872	8,154	4,806	5,168	5,680	5,577	7,626	7,169	5,610	5,496	5,820	5,748
13	2001 Regional Report Surplus Deficit	4,498	1,135	2,905	1,660	2,564	-1,590	-1,825	117	-17	1,270	-2,154	361	2,255	1,334	836
14	2002 Regional Report Surplus Deficit	1,244	140	1,763	989	1,989	205	14	894	1,678	6,537	4,537	4,307	10,342	8,546	3,076
15	2003 Regional Report Surplus Deficit	2,208	887	3,119	1,332	3,158	-1,300	-122	1,451	4,524	3,542	3,188	3,316	8,056	2,247	2,544
16	2004 Regional Report Surplus Deficit	-119	-92	2,266	1,526	4,043	203	181	-224	1,528	3,617	2,378	3,017	7,020	3,266	2,142
17	2005 Regional Report Surplus Deficit	599	1,685	3,917	2,894	4,307	1,844	2,343	4,487	1,995	1,580	898	2,941	5,191	4,035	3,011
18	2006 Regional Report Surplus Deficit	1,685	306	2,630	1,203	4,097	1,342	6,401	7,786	4,484	9,023	5,624	8,826	9,544	4,974	4,932
19	2007 Regional Report Surplus Deficit	2,183	749	2,572	1,644	4,397	1,656	4,554	3,355	8,699	9,752	3,426	4,788	5,944	4,637	4,189
20	2008 Regional Report Surplus Deficit	1,632	326	2,784	936	3,243	590	359	1,016	2,129	3,525	-775	6,358	11,031	8,087	3,242
21	2009 Regional Report Surplus Deficit	3,654	3,499	3,208	1,542	3,801	-714	3,212	1,488	722	6,195	3,896	4,798	6,248	4,160	3,088
22	2010 Regional Report Surplus Deficit	1,032	-87	2,497	1,533	3,047	-1,269	375	-348	248	3,026	-1,177	1,661	9,501	5,998	2,051
23	2011 Regional Report Surplus Deficit	2,341	1,406	3,359	1,386	3,027	2,460	8,317	9,988	7,428	11,260	5,052	6,832	13,250	14,608	6,692
24	2012 Regional Report Surplus Deficit	8,325	4,719	3,735	2,487	3,545	857	5,023	5,857	6,310	11,648	10,072	7,336	11,329	12,437	6,346
25	2013 Regional Report Surplus Deficit	6,165	5,103	3,382	1,665	5,973	4,472	2,122	2,359	2,127	9,847	4,542	5,728	9,118	5,562	4,609
26	2014 Regional Report Surplus Deficit	2,842	1,332	3,648	2,081	3,153	148	3,654	1,032	8,135	8,354	4,563	5,845	8,465	8,480	4,447
27	2015 Regional Report Surplus Deficit	3,193	1,462	3,289	1,624	5,725	3,555	5,998	8,433	9,366	6,180	534	679	2,827	749	3,957
28	2016 Regional Report Surplus Deficit	395	-165	2,649	1,097	2,907	701	1,088	1,796	7,794	9,490	8,261	5,009	5,082	1,953	3,248
29	2017 Regional Report Surplus Deficit	667	143	2,555	2,954	7,526	2,262	5,877	8,822	13,417	13,316	9,751	9,334	12,203	5,709	6,849
30	2018 Regional Report Surplus Deficit	4,676	2,425	2,889	1,574	2,745	1,234	6,867	9,751	6,755	8,087	6,210	10,367	9,120	4,356	5,492

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APPENDIX – REPORTS AVAILABLE UPON REQUEST

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

A. Annual Energy (aMW) – Operating Years 2025 – 2034
B. Monthly Energy (aMW) – Operating Years 2025 – 2034

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



BONNEVILLE POWER ADMINISTRATION
DOE/BP-5289 ▪ August 2024