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 ability 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 applicable, 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 consolidated 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 facilities.

(6) Total long-term liabilities correspond to total non-current liabilities in the consolidated statements of financial position under IFRS .

(7) Total liabilities correspond to a sum of current and non-current liabilities in the consolidated 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) Availability 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 like financing amortization and accretion.

(2) Other non-cash items consists of Alberta market pool incentives, carbon obligation and contract liabilities. Refer to the Reconciliation 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 liabilities 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 Reconciliation 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 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. 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 Consolidated Authoritative Document Glossary.

(2) Alberta Hydro Assets include 13 hydro facilities 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 facility that achieved commercial operation in May 2024.Tower removal at Sinott in 2025, reduced gross installed capacity by 1 MW. Gross installed capacity and availability 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 obligations 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 consolidation 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 facilities 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) Realized 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 applicable, 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) Availability 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 like 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) Realized 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 facility, 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 realized 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 Consolidated 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 affiliates (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 compliance	—	—	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:										
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:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted fuel and purchased power	22	31	637	566	—	3	1,259	—	4	1,263
Carbon compliance	—	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 like 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 facility, 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 compliance	—	—	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 compliance	—	—	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 facility.

(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 like 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 facility, 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 liabilities 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 liabilities on the Consolidated Statements of Financial Position).

(5) The tax equity financing for the Skookumchuck wind facility, 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 Reconciliation 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

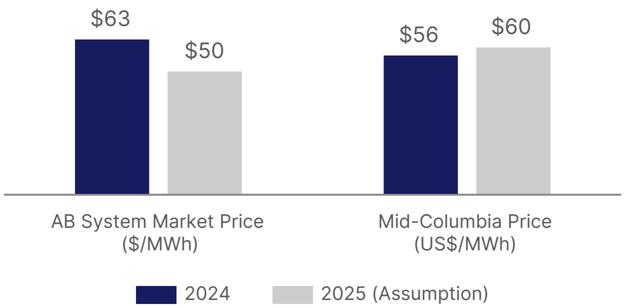
Alberta Hedging

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

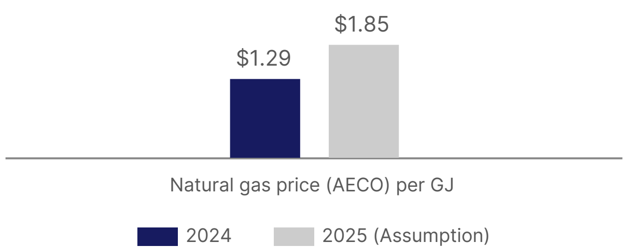
Market Pricing

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 utilization 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 neutralize 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.flipsnack.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 utilization 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 neutralize 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 limited 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 applied 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 Utilities 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. Facilities 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 Applicable, as defined by the TNFD Additional Sector Guidance - Electric Utilities 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 mortality, 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 materiality 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 "Sūṗii 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 million 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

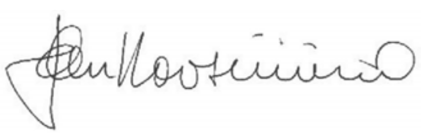
Management's Report

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.

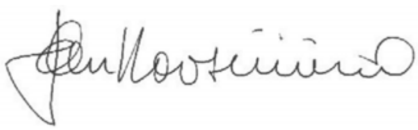
Included in the 2024 Consolidated Financial Statements of TransAlta for equity-accounted investments are one per cent and six per cent of the Company's total and net assets, respectively, as at Dec. 31, 2024, and zero per cent and three per cent of the Company's revenues and net earnings, respectively, 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.

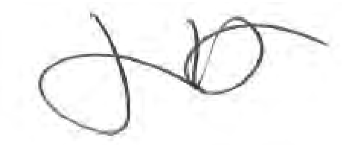
Management has assessed the effectiveness of TransAlta's internal control over financial reporting as at Dec. 31, 2024, and has concluded that such internal control over financial reporting was effective.

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 million recovery, 2022 — $12 million expense).

(2) Net of income tax recovery of $4 million for the year ended Dec. 31, 2024 (2023 — $1 million expense, 2022 — $3 million recovery).

(3) Net of income tax expense of $57 million for the year ended Dec. 31, 2024 (2023 — $10 million 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 liabilities (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 liabilities (Note 25)	**572**	532
	2,569	1,742
Non-current liabilities		
Credit facilities, 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 liabilities (Note 14 and 15)	**305**	274
Contract liabilities (Note 5)	**24**	10
Defined benefit obligation 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-controlling 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-controlling 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 equivalent 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 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.

(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 delivery 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 affiliates (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 Consolidated 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

	2024	2023
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 million 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 Facility	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 liabilities				**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 liabilities				**(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 million (2023 — AU$773 million).

(6) U.S. face value at Dec. 31, 2024, is US$65 million (2023 — US$73 million).

(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 million).

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 million).

(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 Centralia 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 million net decrease in borrowings under credit facilities and a decrease in finance lease obligations of $6 million.

(2) Includes bank overdraft of $1 million and new debt assumed of $232 million 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 million related to the repayment of long-term debt, a $46 million net decrease in borrowings under credit facilities and a decrease in finance lease obligations of $10 million.

(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-controlling 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 facilities, 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	—
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted fuel and purchased power	16	30	470	418	—	—	934	—	5	939
Carbon compliance	—	—	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:										
Unrealized mark-to-market (gain) 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 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:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted fuel and purchased power	22	31	637	566	—	3	1,259	—	4	1,263
Carbon compliance	—	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) liability 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 millions 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 millions)	**302**	276	271
Common shares outstanding at Dec. 31 (in millions)	**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 Australian 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			

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 Sustainability Performance Indicators section of the Report.
(7) As described in the footnote 26 in the Sustainability 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:

Investor Relations
TransAlta Corporation

TransAlta Place
Suite 1400, 1100 1 St SE
Calgary, Alberta T2G 1B1

Phone

North America:
1.800.387.3598 toll-free
Calgary/outside North America:
403.267.2520

Email

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: supplier of goods or services directly to Tier One suppliers. Tier Two suppliers are subcontractors who may not have a direct relationship with the client company. Tier Three: suppliers of raw material or base product to Tier Two suppliers. Tier Three suppliers may, for example, provide minerals for the manufacture of products by Tier Two suppliers.

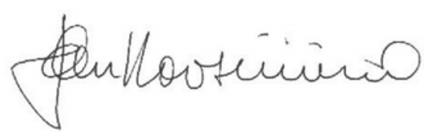
During the course of 2025, we plan to:

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.

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