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.

Table of Contents

This MD&A should be read in conjunction with our unaudited interim condensed consolidated financial statements as at and for the three months ended March 31, 2025 and 2024, and should be read in conjunction with the audited annual consolidated financial statements and MD&A (2024 Annual MD&A) contained within our 2024 Integrated Report. In this MD&A, unless the context otherwise requires, "we", "our", "us", the "Company" and "TransAlta" refer to TransAlta Corporation and its subsidiaries. The unaudited interim condensed 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 March 31, 2025. 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 May 6, 2025. Additional information respecting TransAlta, including our Annual Information form (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 and the Risk Factors section in our AIF for the year ended Dec. 31, 2024.

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.

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 and high-quality contracted assets. Our merchant assets include our unique hydro portfolio and legacy thermal portfolio and a portion of our wind assets. Our merchant exposure is primarily in Alberta, where 58 per cent of our capacity is located with 77 per cent of the capacity available to participate in the merchant market. Our high-quality contracted assets balance the merchant fleet by providing stable long-term earnings and cash flow.

In Alberta, the Company manages its merchant exposure by executing hedging strategies that include a significant base of commercial and industrial (C&I) customers, supplemented with financial hedges. A major portion of our thermal generation capacity in Alberta is hedged to provide greater cash flow certainty while also capturing higher shareholder returns 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.

The following table provides our consolidated ownership by segment of our facilities across the regions in which we operate as of March 31, 2025:

	Hydro		Wind & Solar		Gas		Energy Transition		Total	
As at March 31, 2025	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.

(2) Excludes the gross installed capacity attributable to the Planned Divestitures.

(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 March 31, 2025:

As at March 31, 2025	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) The figures exclude the contracted capacity related to the Planned Divestitures.

Approximately 52 per cent of our total installed capacity is contracted 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 March 31, 2025:

As at March 31, 2025	Hydro	Wind & Solar	Gas(1)	Energy Transition	Total
Alberta	—	7	2	—	3
Canada, excluding Alberta	15	9	7	—	8
U.S.	—	12	1	—	8
Western Australia	—	14	14	—	14
Total weighted average contract life (years)(2)	1	10	4	—	5

(1) Excludes the contracts pertaining to the Planned Divestitures.

(2) The contract life of merchant facilities is included as nil years.

Highlights

For the three months ended March 31, 2025, the Company delivered strong operational performance, while financial performance was partially impacted by softer power prices in Alberta. The Company remains confident in its ability to achieve results within its previously stated guidance range. On Dec. 4, 2024, the Company completed the acquisition of Heartland Generation, which added 1,747 MW to gross installed capacity, excluding the Poplar Hill and Rainbow Lake facilities, (collectively, the Planned Divestitures). IFRS financial statements include the results attributable to 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.

	3 months ended March 31	
(in millions of Canadian dollars except where noted)	**2025**	**2024**
Operational information		
Availability (%)	**94.9**	92.3
Production (GWh)	**6,832**	6,178
Select financial information		
Revenues	**758**	947
Adjusted EBITDA(1)	**270**	342
Adjusted earnings before income taxes(1)	**28**	144
Earnings before income taxes	**49**	267
Adjusted net earnings attributable to common shareholders(1)	**30**	128
Net earnings attributable to common shareholders	**46**	222
Cash flows		
Cash flow from operating activities	**7**	244
Funds from operations(1)	**179**	254
Free cash flow(1)	**139**	221
Per share		
Weighted average number of common shares outstanding	**298**	308
Adjusted net earnings attributable to common shareholders per share(1)(2)	**0.10**	0.41
Net earnings per share attributable to common shareholders, basic and diluted	**0.15**	0.72
Dividends declared per common share	**0.07**	—
Funds from operations per share(1)(2)	**0.60**	0.82
Free cash flow per share(1)(2)	**0.47**	0.72

(1) These are non-IFRS measures and ratios, which 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) and cash flow 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. Also, refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A for more information regarding these non-IFRS measures and ratios, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

(2) Adjusted net earnings attributable to common shareholders per share, 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 Non-IFRS and Supplementary Financial Measures section of this MD&A for more information regarding these non-IFRS measures and ratios.

(in millions of Canadian dollars except where noted)

As at	March 31, 2025	Dec. 31, 2024
Liquidity and capital resources		
Available liquidity[1]	**1,512**	1,616
Adjusted net debt to adjusted EBITDA (times)[2][3]	**3.9**	3.6
Total consolidated net debt[2][4]	**3,983**	3,798
Assets and liabilities		
Total assets	**9,483**	9,499
Total long-term liabilities[5]	**5,572**	5,087
Total liabilities[6]	**7,658**	7,656

(1) Available liquidity is a supplementary financial measure and is calculated as the sum of total available capacity under the committed credit and term facilities and cash and cash equivalents less bank overdraft and the amounts drawn under the non-committed demand facilities.

(2) These are non-IFRS measures and ratios, which 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. Also, refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A for more information regarding these non-IFRS measures and ratios, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

(3) The most directly comparable IFRS ratio to Adjusted net debt to adjusted EBITDA (times) is calculated as total credit facilities, long-term debt and lease liabilities of $3,877 million (Dec. 31, 2024 — $3,808 million) divided by earnings before income taxes for the last four quarters of $101 million (Dec. 31, 2024 — $319 million) and is equal to 38 times (Dec. 31, 2024 — 12 times). Refer to Key non-IFRS financial ratios section of this MD&A for details of the calculation.

(4) The most directly comparable IFRS measure to total consolidated net debt is total credit facilities, long-term debt and lease liabilities, which is equal to $3,877 million (Dec. 31, 2024 — $3,808 million). Refer to the table in the Financial Capital section of this MD&A for more details on the composition of total consolidated net debt.

(5) Total long-term liabilities are equal to total non-current liabilities in the condensed consolidated statements of financial position under IFRS.

(6) Total liabilities are equal to a sum of current and non-current liabilities in the condensed consolidated statements of financial position under IFRS.

Operating Performance

Availability

The following table provides availability (%) by segment:

3 months ended March 31	2025	2024
Hydro	**93.6**	91.9
Wind and Solar	**94.0**	93.4
Gas	**95.5**	94.6
Energy Transition	**97.1**	79.0
Availability (%)	**94.9**	92.3

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.

Availability for the three months ended March 31, 2025, was 94.9 per cent, compared to 92.3 per cent in the same period in 2024. Higher availability compared to the prior period was primarily due to:

- The addition of new facilities, including the Heartland gas facilities in the fourth quarter of 2024 and the White Rock and Horizon Hill wind facilities in the first and second quarters of 2024, which operated at higher availability during the first quarter of 2025;
- Lower unplanned outages at the Centralia facility in the Energy Transition segment; and
- Lower planned major maintenance outages in the Hydro fleet.

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:

	2025			2024		
As at March 31	Actual production (GWh)	LTA generation (GWh)	Production as a % of LTA	Actual production (GWh)	LTA generation (GWh)	Production as a % of LTA
Hydro	**383**	**402**	**95%**	351	402	87%
Wind and Solar(1)	**1,905**	**2,056**	**93%**	1,498	1,644	91%
Gas	**3,504**			3,528		
Energy Transition	**1,040**			801		
Total	**6,832**			6,178		

(1) LTA generation for Wind and Solar increased as a result of new wind facilities, including the White Rock East wind facility commissioned in April 2024 and the Horizon Hill wind facility commissioned in May 2024.

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, 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 models 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.

Total production for the three months ended March 31, 2025, increased by 654 GWh, or 11 per cent, compared to the same period in 2024, primarily due to:

- Production from the Heartland gas facilities acquired in December 2024;
- Production from new wind and solar facilities, including the White Rock West and East wind facilities commissioned in January and April 2024, respectively, and the Horizon Hill wind facility commissioned in May 2024;
- Improved availability at the Centralia facility due to lower unplanned outages; and
- Higher wind resource across all regions; partially offset by
- Higher dispatch optimization in Alberta due to lower market prices; and
- Lower production in Australia due to lower customer demand.

Market Pricing

3 months ended March 31	2025	2024
Alberta spot power price ($/MWh)	**40**	99
Mid-Columbia spot power price (US$/MWh)	**50**	104
Ontario spot power price ($/MWh)	**63**	33
Natural gas price (AECO) per GJ ($)	**2.03**	1.94

For the three months ended March 31, 2025, spot power prices in Alberta were 59 per cent lower compared to the same period in 2024, driven by a generally mild winter and increased supply from new renewable and gas-fired facilities.

Spot power prices in the Pacific Northwest were 52 per cent lower compared to to the same period in 2024, also due to a milder winter.

Ontario spot power prices were 91 per cent higher compared to the same period in 2024, driven by decreased supply in the market due to nuclear refurbishments occurring in the period.

AECO natural gas prices for the three months ended March 31, 2025, were comparable with prices for the same period in the prior year.

Financial Performance Review of Consolidated Information

3 months ended March 31	2025	2024
Revenues	**758**	947
Fuel and purchased power	**277**	323
Carbon compliance	**49**	40
Operations, maintenance and administration	**173**	134
Depreciation and amortization	**146**	124
Asset impairment charges (reversals)	**15**	1
Fair value change in contingent consideration payable	**34**	—
Interest expense	**93**	69
Earnings before income taxes	**49**	267
Income tax expense	**7**	29
Net earnings attributable to common shareholders	**46**	222
Net (losses) earnings attributable to non-controlling interests	**(4)**	16

First Quarter Variance Analysis (2025 versus 2024)

Revenues totalling $758 million, decreased by $189 million, or 20 per cent, compared to the same period in 2024, primarily due to:

- Lower power prices in Alberta;
- Lower revenue at Centralia due to higher economic dispatch driven by lower market prices;
- Lower revenue from derivatives and other trading activities in the Wind and Solar segment driven by higher unrealized mark-to-market losses on 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 in the Energy Marketing segment due to comparatively muted market volatility across North American natural gas and power markets and lower realized settled trades in 2025 in comparison to the same period in the prior year; partially offset by
- Higher revenue in the Gas segment with the acquisition of Heartland;
- Full quarter impact of commercial operation of the White Rock and Horizon Hill wind facilities; and
- Higher revenue from derivatives and other trading activities in the Gas segment primarily related to favourable hedging positions in the current period.

Fuel and purchased power costs totalling $277 million, decreased by $46 million, or 14 per cent, compared to the same period in 2024, primarily due to lower purchased power costs driven by lower Mid-Columbia prices in the Energy Transition segment.

Carbon compliance costs totalling $49 million, increased by $9 million compared to the same period in 2024, primarily due to an increase in the carbon price from $80 per tonne in 2024 to $95 per tonne in 2025.

OM&A expenses totalling $173 million, increased by $39 million, or 29 per cent, compared to the same period in 2024, primarily due to:

- Higher spending to support strategic and growth initiatives;
- The addition of the Heartland facilities and associated corporate costs in the fourth quarter of 2024;
- The addition of the White Rock and Horizon Hill wind facilities in the first and second quarters of 2024; and
- Higher spending related to the planning and design of an upgrade to our enterprise resource planning (ERP) system.

Depreciation and amortization totalling $146 million, increased by $22 million, or 18 per cent, compared to the same period in 2024, primarily due to:

- The addition of the Heartland facilities in the fourth quarter of 2024; and
- The addition of the White Rock and Horizon Hill wind facilities in the first and second quarters of 2024.

Asset impairment charges totalling $15 million, increased by $14 million, compared to the same period in 2024, primarily due to:

- An impairment charge on Planned Divestiture assets classified as Assets Held for Sale;
- 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; partially offset by

- An impairment reversal related to certain energy transition assets reclassified to Assets Held for Sale.

Fair value change in contingent consideration payable totalling $34 million in the first quarter of 2025 was driven by updated expectations of the fair value less costs to sell on the Planned Divestitures.

Interest expense totalling $93 million, increased by $24 million, or 35 per cent, compared to the same period in 2024, primarily due to lower capitalized interest resulting from lower construction activity in 2025 compared to the same period in 2024.

Earnings before income taxes totalling $49 million, decreased by $218 million, or 82 per cent, compared to the same period in 2024, due to the above noted items. Refer to the Segment Financial Performance and Operating Results section for additional information.

Income tax expense totalling $7 million, decreased by $22 million, or 76 per cent, compared to the same period in 2024, due to the above noted items.

Net loss attributable to non-controlling interests totalling $4 million, decreased from net earnings attributable to non-controlling interests by $20 million, or 125 per cent, compared to the same period in 2024, primarily due to lower net earnings for TransAlta Cogeneration, LP (TA Cogen) resulting from lower merchant pricing in the Alberta market.

Adjusted EBITDA

For the three months ended March 31, 2025, the Company's Adjusted EBITDA was $270 million as compared to $342 million in 2024, a decrease of $72 million, or 21 per cent. The major factors impacting Adjusted EBITDA are summarized in the following table:

	3 months ended March 31
Adjusted EBITDA for the three months ended March 31, 2024[1]	342
Hydro: Lower primarily due to lower spot power prices and ancillary services prices in the Alberta market, partially offset by higher merchant and ancillary services volumes due to higher water reserves in the first quarter of 2025 and favourable hedging positions settled, which generated positive contributions over settled spot prices in the first quarter of 2025.	(40)
Wind and Solar: Higher primarily due to higher revenues from the Horizon Hill and White Rock West and East wind facilities due to full first quarter production in 2025 and higher production volumes across all regions, partially offset by lower Alberta pool prices and higher OM&A from the addition of new wind facilities.	13
Gas: Lower primarily due to higher OM&A related to the addition of the Heartland facilities, lower merchant volumes due to lower market prices driven by milder weather and new gas generation in Alberta and lower spot power prices in Alberta, partially offset by favourable hedge positions settled, and the addition of the Heartland facilities.	(21)
Energy Transition: Higher primarily due to lower fuel and purchased power costs, partially offset by increased economic dispatch driven by lower market prices, which negatively impacted merchant revenues.	10
Energy Marketing: Lower primarily due to comparatively muted market volatility across North American natural gas and power markets and lower realized settled trades in the first quarter of 2025 compared to the same period in 2024.	(18)
Corporate: Lower primarily due to increased spending to support strategic growth projects and the addition of corporate costs related to the acquisition of Heartland.	(16)
Adjusted EBITDA[2] for the three months ended March 31, 2025	**270**

(1) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. During the second quarter of 2024, our Adjusted EBITDA composition was amended to exclude the impact of acquisition-related transaction and restructuring costs. Therefore, the Company has applied this composition to all previously reported periods. Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A for more details.

(2) Adjusted EBITDA is a non-IFRS measure. Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A. The most directly comparable IFRS measure is earnings before income taxes of $49 million for the three months ended March 31, 2025 and $267 million for the three months ended March 31, 2024, respectively. Refer to Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segments section of this MD&A.

Free Cash Flow

For the three months ended March 31, 2025, the Company's FCF decreased by $82 million, or 37 per cent, compared to the same period in 2024. Refer to the Reconciliation of Cash Flow from Operations to FFO and FCF section in this MD&A for more details. The major factors impacting FCF are summarized in the following table:

	3 months ended March 31
FCF for the three months ended March 31, 2024	221
Lower Adjusted EBITDA[(1)] due to the items noted above.	(72)
Higher sustaining capital expenditures due to the receipt of a lease incentive related to the Company's head office during the first quarter of 2024 and higher major maintenance at our Canadian gas fleet during the first quarter of 2025.	(24)
Higher net interest expense[(2)] due to lower capitalized interest resulting from lower construction activity in the first quarter of 2025 compared to the same period in 2024.	(24)
Lower distributions paid to subsidiaries' non-controlling interests relating to lower TA Cogen net earnings resulting from lower merchant pricing in the Alberta market.	19
Lower current income tax expense due to lower earnings before income taxes in 2025 compared to the same period in 2024.	14
Lower provisions accrued in the current period compared to the same period in prior year resulting in higher FCF.	8
Other non-cash items[(3)]	(5)
Other[(4)]	2
FCF[(5)] for the three months ended March 31, 2025	**139**

(1) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. During the second quarter of 2024, our Adjusted EBITDA composition was amended to exclude the impact of acquisition-related transaction and restructuring costs. Therefore, the Company has applied this composition to all previously reported periods. Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A.

(2) Net interest expense is a non-IFRS measure, is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to Non-IFRS and Supplementary Financial Measures section of this MD&A for more information regarding this measure. The most directly comparable IFRS measure is interest expense of $93 million for the three months ended March 31, 2025 (March 31, 2024 — $69 million).

(3) Other non-cash items consists of contract liabilities, onerous contracts and long-term incentive accruals.

(4) Other consists of lower realized foreign exchange loss, higher decommissioning and higher restoration costs settled.

(5) FCF is a non-IFRS measure, 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 Non-IFRS and Supplementary Financial Measures section of this MD&A for more information regarding this measure. The most directly comparable IFRS measure is cash flow from operations, which was $7 million and $244 million for the three months ended March 31, 2025 and 2024, respectively. Refer to the Cash Flows section of this MD&A.

Capital Expenditures

Sustaining capital and growth and development expenditures represent supplementary financial measures used to present our spend related to the safe and reliable operation of our existing facilities and the construction of projects, respectively. The sum of sustaining capital expenditures and growth and development expenditures is approximately equal to the additions to property, plant and equipment and intangible assets during the period in the condensed consolidated statement of cash flows.

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. Sustaining capital are capital expenditures incurred for major maintenance to sustain the existing capacity or production of the existing asset to the end of its useful life.

The Company's sustaining capital expenditures by segment are summarized in the table below:

3 months ended March 31	2025	2024
Hydro	4	3
Wind and Solar	4	2
Gas	11	3
Corporate	4	(9)
Sustaining capital expenditures	23	(1)

Total sustaining capital expenditures during the three months ended March 31, 2025 were $24 million higher compared to the same period in 2024, primarily due to:

- The receipt of a lease incentive related to the Company's head office during the first quarter of 2024, included in the Corporate segment; and
- Higher major maintenance for our Canadian gas fleet due to timing of spend, including the gas facilities acquired from Heartland.

Growth and Development Capital Expenditures

Growth and development capital expenditures are impacted by the timing and construction of projects within the development pipeline. Growth capital represents capital expenditures incurred that will add megawatts to the Company or will generate new incremental revenues and consists of engineering, design, contracting, permitting, payroll and overhead expenditures that meet capitalization criteria.

The following table provides our growth and development spending by segment:

3 months ended March 31	2025	2024
Hydro	—	2
Wind and Solar	—	41
Gas	11	12
Growth and development expenditures	11	55

In the first quarter of 2025, growth and development capital expenditures were lower compared to the same period in 2024, as many of the development projects achieved commercial operation in the first half of 2024. Refer to the Strategic Priorities section of this MD&A for more details.

Significant and Subsequent Events

Senior Notes Offering

On March 24, 2025, the Company issued $450 million of senior notes with a fixed annual coupon of 5.625 per cent, maturing on March 24, 2032. The notes are unsecured and rank equally in right of payment with all existing and future senior indebtedness and senior in right of payment to all future subordinated indebtedness. Interest payments on the notes are made semi-annually, on March 24 and Sept. 24, with the first payment commencing Sept. 24, 2025.

On March 25, 2025, the Company repaid its $400 million variable rate term loan facility in advance of the scheduled maturity date of Sept. 7, 2025, with the proceeds received from the $450 million senior notes offering.

Nova Clean Energy, LLC

During the first quarter of 2025, the Company made a strategic investment in Nova Clean Energy, LLC (Nova), a developer of renewable energy projects. The investment includes a US$75 million term loan and US$100 million revolving facility. At closing of the transaction, US$74 million was drawn by Nova under the credit facilities. The outstanding principal under the term loan and the revolving facility bear interest of seven per cent per annum with interest due quarterly. The terms of the term loan and the revolving facility are six and five years, respectively, unless accelerated. The term loan is convertible to a minority equity interest at any time, prior to maturity, at the option of the Company and any remaining unused term loan commitments at the time of conversion would be terminated. This investment provides the Company with the exclusive right to purchase Nova's late-stage development projects in the western U.S.

Mothballing of Sundance 6

As previously communicated, on April 1, 2025, the Company mothballed the Sundance Unit 6 facility. The Company initially provided notice to the Alberta Electric System Operator (AESO) on Nov. 4, 2024, that Sundance Unit 6 would 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.

Declared Increase in Common Share Dividend

On Feb. 19, 2025, the Company's Board of Directors approved a $0.02 annualized increase to the common share dividend, an eight per cent increase, and declared a dividend of $0.065 per common share 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.

Normal Course Issuer Bid (NCIB) and Automatic Securities Purchase Plan (ASPP)

TransAlta remains committed to enhancing shareholder returns through appropriate capital allocation such as share buybacks and its quarterly dividend.

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.

On Feb. 19, 2025 the Company announced it was allocating up to $100 million to be returned to shareholders in the form of share repurchases.

On March 25, 2025, the Company entered into an ASPP to facilitate repurchases of TransAlta's common shares under its NCIB. Under the ASPP, the Company's broker may purchase common shares from the effective date of the ASPP until the termination of the ASPP. All purchases of common shares made under the ASPP will be included in determining the number of common shares purchased under the NCIB. The ASPP will terminate on the earliest of: (a) May 8, 2025; (b) the date on which the maximum purchase limits under the ASPP are reached; or (c) the date on which the Company terminates the ASPP in accordance with its terms.

For the three months ended March 31, 2025, the Company purchased and cancelled a total of 294,200 common shares, at an average price of $13.59 per common share, for a total cost of $4 million, including taxes.

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 three months ended March 31:

3 months ended March 31	2025	2024
Hydro	**47**	87
Wind and Solar	**102**	89
Gas	**104**	125
Energy Transition	**37**	27
Energy Marketing	**21**	39
Corporate	**(41)**	(25)
Total adjusted EBITDA[(1)(2)]	**270**	342
Adjusted earnings before income taxes[(1)]	**28**	144
Earnings before income taxes	**49**	267
Adjusted net earnings attributable to common shareholders[(1)]	**30**	128
Net earnings attributable to common shareholders	**46**	222

(1) These are non-IFRS measures, which are not defined, have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A for more information regarding these measures. The most directly comparable IFRS measure to Adjusted EBITDA and Adjusted earnings before income taxes is earnings before income taxes. The most directly comparable IFRS measure to Adjusted net earnings attributable to common shareholders is Net earnings attributable to common shareholders. Refer to Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segments section of this MD&A.

(2) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. During the second quarter of 2024, our Adjusted EBITDA composition was amended to exclude the impact of acquisition-related transaction and restructuring costs. Therefore, the Company has applied this composition to all previously reported periods. Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A.

Adjusted earnings before income taxes for the three months ended March 31, 2025 decreased by $116 million, or 81 per cent, compared to the same period in 2024, primarily due to:

The factors causing lower adjusted EBITDA described in the Adjusted EBITDA section of this MD&A; and

- Higher depreciation and amortization due to the addition of the Heartland gas facilities and White Rock and Horizon Hill wind facilities;
- Higher interest expense due to lower capitalized interest resulting from lower construction activity in the first quarter of 2025 compared to the same period in 2024.

Adjusted net earnings attributable to common shareholders for the three months ended March 31, 2025 decreased by $98 million, or 77 per cent, compared to the same period in 2024, primarily due to:

- The factors causing lower adjusted earnings before income taxes described above; and
- Lower calculated tax recovery on adjustments and reclassifications in 2025; partially offset by
- Lower current income tax expense due to lower earnings before income taxes in 2025 compared to the same period in 2024.

Earnings before income taxes for the three months ended March 31, 2025, decreased by $218 million, or 82 per cent, compared to the same period in 2024, primarily due to:

- The factors causing lower adjusted earnings before income taxes noted above;
- Higher unrealized mark-to-market losses recorded in the Wind and Solar segment primarily related to long-term wind energy sales related to the Oklahoma facilities;
- Lower unrealized mark-to-market gains recorded in the Gas segment primarily related to lower volumes hedged in the current period;
- Higher asset impairment charges on the Planned Divestiture assets classified as Assets Held for Sale, offset by a fair value gain on the contingent consideration payable in the first quarter of 2025 driven by updated expectations of the fair value less costs to sell on the Planned Divestitures;
- Higher asset impairment charges 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; impairment charges related to development projects that are no longer proceeding, partially offset by an impairment reversal related to certain energy transition assets reclassified to assets held for sale; and
- Higher spending relating to planning and design work on a planned upgrade to our ERP system; partially offset by
- Higher unrealized mark-to-market gains recorded in the Hydro segment primarily related to the favourable changes in forward prices.

Net earnings attributable to common shareholders for the three months ended March 31, 2025, decreased by $176 million, or 79 per cent, compared to the same period in 2024, primarily due to:

- The factors causing lower earnings before income taxes above; partially offset by
- Lower current income tax expense due to lower earnings before income taxes in 2025 compared to the same period in 2024; and
- Net loss attributable to non-controlling interests compared to net earnings in the same period in 2024, primarily due to lower net earnings for TA Cogen resulting from lower merchant pricing in the Alberta market.

Hydro

3 months ended March 31	2025	2024	Change	
Gross installed capacity (MW)	922	922	—	— %
LTA generation (GWh)	402	402	—	— %
Availability (%)	93.6	91.9	1.7	2 %
Production				
Contract production (GWh)	38	38	—	— %
Merchant production (GWh)	345	313	32	10 %
Total energy production (GWh)	383	351	32	9 %
Ancillary service volumes (GWh)[1]	713	661	52	8 %
Alberta Hydro Assets revenues[2]	26	49	(23)	(47)%
Other Hydro Assets revenues and other Hydro revenues[3]	9	8	1	13 %
Alberta Hydro ancillary services revenues[1]	20	36	(16)	(44)%
Environmental and tax attributes revenues	10	14	(4)	(29)%
Adjusted revenues[4]	65	107	(42)	(39)%
Fuel and purchased power	4	6	(2)	(33)%
Adjusted gross margin[4]	61	101	(40)	(40)%
Adjusted OM&A[4]	13	13	—	— %
Taxes, other than income taxes	1	1	—	— %
Adjusted EBITDA[4]	47	87	(40)	(46)%
Depreciation and amortization	(9)	(7)	(2)	29 %
Adjusted earnings before income taxes[4]	38	80	(42)	(53)%
Earnings before income taxes	59	85	(26)	(31)%
Supplemental Information:				
Gross revenues per MWh				
Alberta Hydro Assets revenues ($/MWh)[2]	75	157	(82)	(52)%
Alberta Hydro Assets ancillary services revenues ($/MWh)[1]	28	54	(26)	(48)%

(1) Alberta Hydro ancillary services revenues is a supplementary financial measure. Alberta Hydro ancillary services revenues are revenues earned from providing 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 as described in the AESO Consolidated Authoritative Document Glossary. Revenues per MWh is calculated by dividing Alberta Hydro ancillary services revenues by ancillary service volumes in MWh.

(2) Alberta Hydro Assets revenues is a supplementary financial measure and is comprised of revenues from 13 hydro facilities on the Bow and North Saskatchewan river systems, as well as revenues from swaps and forward hedges. Revenues per MWh is calculated by dividing Alberta Hydro revenues by merchant production in MWh.

(3) Other Hydro Assets revenues is a supplementary financial measure and consists of revenues from our hydro facilities in British Columbia, Ontario and Alberta (other than the Alberta Hydro Assets). Other Hydro revenues is a supplementary financial measure and includes revenues from our transmission business and other contractual arrangements, including the flood mitigation agreement with the Government of Alberta and black start services.

(4) Adjusted revenues, adjusted gross margin, adjusted OM&A, adjusted EBITDA and adjusted earnings (loss) before income taxes are non-IFRS measures, 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 Non-IFRS and Supplementary Financial Measures section of this MD&A for more information regarding these measures. The most directly comparable IFRS measure to adjusted revenues is revenues $86 million (March 31, 2024 — $112 million), to adjusted gross margin - gross margin $82 million (March 31, 2024 — $106 million), to adjusted OM&A - OM&A $13 million (March 31, 2024 — $13 million), to Adjusted EBITDA and Adjusted earnings before income taxes - earnings before income taxes $59 million (March 31, 2024 — $85 million).

Adjusted revenues for the three months ended March 31, 2025, decreased compared to the same period in 2024, primarily due to:

- Lower spot power and ancillary services prices in the Alberta market; partially offset by
- Higher merchant and ancillary services volumes due to higher water reserves in the first quarter of 2025 ; and
- Realized premiums above spot power prices and positive contributions from hedging.

Adjusted EBITDA for the three months ended March 31, 2025, decreased compared to the same period in 2024, primarily due to lower adjusted revenues as explained by the factors above.

Adjusted earnings before income taxes for the three months ended March 31, 2025, decreased compared to the same period in 2024 mainly due to lower adjusted EBITDA as explained above.

Earnings before income taxes for the three months ended March 31, 2025, decreased compared to the same period in 2024 due to lower adjusted earnings before income taxes, partially offset by higher unrealized mark-to-market gains due to more favourable hedges in the current period.

For further discussion on the Alberta market conditions and pricing, refer to the Optimization of the Alberta Portfolio section of this MD&A.

Wind and Solar

3 months ended March 31	2025	2024	Change	
Gross installed capacity (MW)[1]	2,587	2,184	403	18 %
LTA generation (GWh)	2,056	1,644	412	25 %
Availability (%)	94.0	93.4	0.6	1 %
Production				
Contract production (GWh)	1,610	1,154	456	40 %
Merchant production (GWh)	295	344	(49)	(14)%
Total production (GWh)	1,905	1,498	407	27 %
Revenues	119	102	17	17 %
Environmental and tax attributes revenues	26	18	8	44 %
Adjusted revenues[2][3]	145	120	25	21 %
Fuel and purchased power	10	9	1	11 %
Carbon compliance	1	—	1	— %
Adjusted gross margin[2][3]	134	111	23	21 %
Adjusted OM&A[2][3]	29	20	9	45 %
Taxes, other than income taxes	5	4	1	25 %
Net other operating income	(2)	(2)	—	— %
Adjusted EBITDA[2][3]	102	89	13	15 %
Depreciation and amortization	(53)	(43)	(10)	23 %
Adjusted earnings before income taxes[2][3]	49	46	3	7 %
Earnings before income taxes[4]	11	59	(48)	(81)%

(1) Gross installed capacity and availability for 2025 include the 202 MW White Rock East and 202 MW Horizon Hill wind facilities that achieved commercial operation in April and May 2024, respectively. Tower removal at Sinott in December 2024, reduced gross installed capacity by 1 MW.

(2) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(3) Adjusted revenues, adjusted gross margin, adjusted OM&A, adjusted EBITDA and adjusted earnings before income taxes are non-IFRS measures, 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 Non-IFRS and Supplementary Financial Measures section of this MD&A for more information regarding these measures. The most directly comparable IFRS measure to adjusted revenues is revenues $100 million (March 31, 2024 — $133 million), to adjusted gross margin - gross margin $89 million (March 31, 2024 — $124 million), to adjusted OM&A - OM&A $28 million (March 31, 2024 — $19 million), to adjusted EBITDA and adjusted earnings before income taxes - earnings before income taxes $11 million (March 31, 2024 — $59 million).

(4) Earnings before income taxes exclude the contribution from Skookumchuck wind facility.

Adjusted revenues for the three months ended March 31, 2025, increased compared to the same period in 2024, primarily due to:

- Higher revenues from the full quarter impact of commercial operation of the White Rock and Horizon Hill wind facilities; and
- Higher production volumes across all regions due to higher wind resource; partially offset by
- Lower Alberta pool prices.

Adjusted EBITDA for the three months ended March 31, 2025, increased compared to the same period in 2024, 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.

Adjusted earnings before income taxes for the three months ended March 31, 2025, increased compared to the same period in 2024 due to higher adjusted EBITDA as explained above, partially offset by higher depreciation and amortization due to the addition of new wind facilities.

Earnings before income taxes for the three months ended March 31, 2025, decreased compared to the same period in 2024 due to higher adjusted earnings before income taxes and higher unrealized mark-to-market losses on the long-term wind energy sales related to the Oklahoma facilities.

Gas

3 months ended March 31	2025	2024	Change	
Gross installed capacity (MW)[1]	4,834	3,087	1,747	57 %
Availability (%)	95.5	94.6	0.9	1 %
Production				
Contract sales volume (GWh)	2,550	1,722	828	48 %
Merchant sales volume (GWh)	1,292	2,045	(753)	(37)%
Purchased power (GWh)[2]	(338)	(239)	(99)	41 %
Total production (GWh)	3,504	3,528	(24)	(1)%
Adjusted revenues[3]	366	346	20	6 %
Adjusted fuel and purchased power[3]	161	142	19	13 %
Carbon compliance	49	40	9	23 %
Adjusted gross margin[3]	156	164	(8)	(5)%
Adjusted OM&A[3]	57	46	11	24 %
Taxes, other than income taxes	5	3	2	67 %
Net other operating income	(10)	(10)	—	— %
Adjusted EBITDA[3][4]	104	125	(21)	(17)%
Depreciation and amortization	(64)	(55)	(9)	16 %
Adjusted earnings before income taxes[3]	40	70	(30)	(43)%
Earnings before income taxes	65	158	(93)	(59)%

(1) Gross installed capacity and availability for 2025 include the 1,747 MW Heartland gas facilities and exclude the Planned Divestitures.

(2) Power required to fulfil contractual obligations is included in purchased power.

(3) Adjusted revenues, adjusted fuel and purchased power, adjusted gross margin, adjusted OM&A, adjusted EBITDA and adjusted earnings (loss) before income taxes are non-IFRS measures, are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. The most directly comparable IFRS measure to adjusted revenues is revenues $390 million (March 31, 2024 — $433 million), to adjusted fuel and purchased power - fuel and purchased power $163 million (March 31, 2024 — $142 million), to adjusted OM&A - OM&A $59 million (March 31, 2024 — $46 million), to adjusted gross margin - gross margin $178 million (March 31, 2024 — $251 million), to adjusted EBITDA and adjusted earnings before income taxes - earnings before income taxes $65 million (March 31, 2024 — $158 million).

(4) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. Therefore, the Company has applied this composition to all previously reported periods. Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A.

Adjusted revenues for the three months ended March 31, 2025, increased compared to the same period in 2024, primarily due to:

- Addition of gas facilities from Heartland;
- Favourable hedge positions settled, which generated positive contributions over settled spot prices in Alberta; partially offset by
- Higher dispatch optimization due to lower market prices driven by milder weather and new gas generation in Alberta; and
- Lower pool and realized power prices in the Alberta market.

Adjusted EBITDA for the three months ended March 31, 2025, decreased compared to the same period in 2024, primarily due to:

- Higher natural gas prices;
- An increase in the carbon price from $80 to $95 per tonne, impacting gross margin from our Canadian gas facilities; and
- Higher OM&A related to the addition of the Heartland facilities; partially offset by
- Higher adjusted revenues explained above.

Adjusted earnings before income taxes for the three months ended March 31, 2025, decreased compared to the same period in 2024 due to:

- Lower adjusted EBITDA as explained above; and
- Higher depreciation due to the addition of the Heartland facilities.

Earnings before income taxes for the three months ended March 31, 2025, decreased compared to the same period in 2024 due to:

- Lower adjusted earnings before income taxes;
- Lower unrealized mark-to-market gains due to less favourable hedges in the current period; and
- Impairment charge on the Planned Divestitures recognized in the first quarter of 2025; partially offset by
- Fair value gain on the contingent consideration payable driven by updated expectations of the fair value less costs to sell on the Planned Divestitures.

Energy Transition

3 months ended March 31	2025	2024	Change	
Gross installed capacity (MW)	671	671	—	— %
Availability (%)	97.1	79.0	18.1	23 %
Production				
Contract sales volume (GWh)	648	830	(182)	(22)%
Merchant sales volume (GWh)	1,103	933	170	18 %
Purchased power (GWh)(1)	(711)	(962)	251	(26)%
Total production (GWh)	1,040	801	239	30 %
Adjusted revenues(2)	153	211	(58)	(27)%
Fuel and purchased power	98	166	(68)	(41)%
Adjusted gross margin(2)	55	45	10	22 %
OM&A	17	18	(1)	(6)%
Taxes, other than income taxes	1	—	1	100 %
Adjusted EBITDA(2)(3)	37	27	10	37 %
Depreciation and amortization	(15)	(16)	1	(6)%
Adjusted earnings before income taxes(2)	22	11	11	100 %
Earnings before income taxes	47	20	27	135 %
Supplemental information:				
Highvale mine reclamation spend(4)	3	3	—	— %
Centralia mine reclamation spend(4)	4	3	1	33 %

(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) Adjusted revenues, adjusted gross margin, adjusted EBITDA and adjusted earnings before income taxes are non-IFRS measures, are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. The most directly comparable IFRS measure to adjusted revenues is revenues $154 million (March 31, 2024 — $217 million), to adjusted gross margin - gross margin $56 million (March 31, 2024 — $51 million), to Adjusted EBITDA and Adjusted earnings before income taxes - earnings before income taxes $47 million (March 31, 2024 — $20 million).

(3) During the first quarter of 2025 our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions. Therefore, the Company has applied this composition to all previously reported periods. Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A.

(4) Highvale and Centralia mine reclamation spend, which represent the costs necessary to bring the sites to their original condition, are supplementary financial measures and are included in the Decommissioning and restoration liabilities settled during the period in the consolidated statements of financial position under IFRS.

Adjusted revenues for the three months ended March 31, 2025, decreased compared to the same period in 2024, primarily due to lower Mid-Columbia prices.

Adjusted EBITDA for the three months ended March 31, 2025, increased compared to the same period in 2024, primarily due to:

- Lower purchased power costs driven by higher availability, which resulted in fewer repurchases to fulfill contractual obligations during outages; partially offset by
- Lower revenues as explained by the factors above.

Adjusted earnings before income taxes for the three months ended March 31, 2025, increased compared to the same period in 2024 due to higher adjusted EBITDA as explained above.

Earnings before income taxes for the three months ended March 31, 2025, increased compared to the same period in 2024 due to higher adjusted earnings before income taxes and impairment reversal related to generation equipment in the current period.

Mine reclamation spend for the three months ended March 31, 2025, was consistent with the same period in 2024.

Energy Marketing

3 months ended March 31	2025	2024	Change	
Adjusted revenues[1]	28	49	(21)	(43)%
OM&A	7	10	(3)	(30)%
Adjusted EBITDA[1][2]	21	39	(18)	(46)%
Depreciation and amortization	(2)	(1)	(1)	100 %
Adjusted earnings before income taxes[1][2]	19	38	(19)	(50)%
Earnings before income taxes	18	41	(23)	(56)%

(1) Adjusted revenues, adjusted EBITDA and adjusted earnings before income taxes are non-IFRS measures, are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. The most directly comparable IFRS measure to adjusted revenues is revenues $27 million (March 31, 2024 — $52 million), to Adjusted EBITDA and Adjusted earnings before income taxes - earnings before income taxes $18 million (March 31, 2024 — $41 million).

(2) During the first quarter of 2025 our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions. Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A.

Adjusted revenues and Adjusted EBITDA for the three months ended March 31, 2025, decreased compared to the same period in 2024, primarily due to comparatively muted market volatility across North American natural gas and power markets and lower realized settled trades in 2025 in comparison to the same period in the prior year.

Adjusted earnings before income taxes for the three months ended March 31, 2025, decreased compared to the same period in 2024 mainly due to lower adjusted revenues as explained above.

Earnings before income taxes for the three months ended March 31, 2025 decreased compared to the same period in 2024 due to lower adjusted earnings before income taxes.

Corporate

3 months ended March 31	2025	2024	Change	
Adjusted OM&A(1)(3)	41	25	16	64%
Adjusted EBITDA(2)(3)	(41)	(25)	(16)	64 %
Depreciation and amortization	(5)	(4)	(1)	25 %
Equity income from associate	(1)	(2)	1	(50)%
Interest income	5	7	(2)	(29)%
Interest expense	(94)	(69)	(25)	36 %
Realized foreign exchange loss	(4)	(8)	4	(50%)
Adjusted loss before income taxes(2)	(140)	(101)	(39)	39 %
Loss before income taxes	(151)	(96)	(55)	57%

(1) The most directly comparable IFRS measure is OM&A, which was $49 million for the three months ended March 31, 2025 (March 31, 2024 — $28 million).

(2) Adjusted EBITDA and adjusted earnings (loss) before income taxes are non-IFRS measures, are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. The most directly comparable IFRS measure is loss before income taxes, which was $151 million for the three months ended March 31, 2025 (March 31, 2024 — $96 million).

(3) During the second quarter of 2024 our Adjusted EBITDA composition was amended to exclude the impact of acquisition-related transaction and restructuring costs. Therefore, the Company has applied this composition to all previously reported periods. Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A.

Adjusted EBITDA for the three months ended March 31, 2025, decreased compared to the same period in 2024, primarily due to increased spending to support strategic and growth initiatives and the addition of corporate costs related to Heartland.

Adjusted loss before income taxes for the three months ended March 31, 2025, increased compared to the same period in 2024 due to:

- Lower Adjusted EBITDA as explained above; and
- Higher interest expense due to lower capitalized interest resulting from lower construction activity in 2025 compared to the same period in 2024.

Loss before income taxes for the three months ended March 31, 2025, increased compared to the same period in 2024 due to:

- Lower adjusted loss before income taxes as explained above;
- Higher spending relating to planning and design work on a planned upgrade to our ERP system; and
- Higher asset impairment charges related to development costs for projects that are no longer proceeding.

Performance by Segment with Supplemental Geographical Information

The following table provides adjusted EBITDA by segment across the regions we operate in:

3 Months Ended March 31, 2025	Hydro	Wind & Solar(3)	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	47	10	50	(2)	21	(41)	85
Canada, excluding Alberta	—	48	27	—	—	—	75
U.S.	—	42	3	39	—	—	84
Western Australia	—	2	24	—	—	—	26
Adjusted EBITDA(1)	**47**	**102**	**104**	**37**	**21**	**(41)**	**270**
Adjusted earnings (loss) before income taxes(1)	**38**	**49**	**40**	**22**	**19**	**(140)**	**28**
Earnings (loss) before income taxes	**59**	**11**	**65**	**47**	**18**	**(151)**	**49**

3 Months Ended March 31, 2024	Hydro	Wind & Solar(3)	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	87	24	75	(3)	39	(25)	197
Canada, excluding Alberta	—	40	24	—	—	—	64
U.S.	—	23	3	30	—	—	56
Western Australia	—	2	23	—	—	—	25
Adjusted EBITDA(1)(2)	87	89	125	27	39	(25)	342
Adjusted earnings (loss) before income taxes(1)	80	46	70	11	38	(101)	144
Earnings (loss) before income taxes	85	59	158	20	41	(96)	267

(1) Adjusted EBITDA and adjusted earnings (loss) before income taxes are non-IFRS measures, are not defined, have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers.

(2) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. During the second quarter of 2024, our Adjusted EBITDA composition was amended to exclude the impact of acquisition-related transaction and restructuring costs. Therefore, the Company has applied this composition to all previously reported periods. Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A.

(3) Earnings before income taxes for the Wind and Solar segment exclude the contribution from Skookumchuck wind facility.

Optimization of the Alberta Portfolio

The Alberta electricity portfolio metrics disclosed below are supplementary financial measures used to present the detailed performance by segment for the Alberta market.

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 enhanced and further diversified 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 well positioned to respond to price volatility and deliver peaking capacity in periods of higher demand in the Alberta market.

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 that is not correlated with a change in production. During the first quarter of 2025, there were periods of low market prices, and the Company opted not to generate production from the thermal fleet, which resulted in thermal generation sold through C&I contracts and financial hedges exceeding 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:

	2025					2024				
3 months ended March 31	**Hydro**	**Wind & Solar**	**Gas[4]**	**Energy Transition**	**Total**	**Hydro**	**Wind & Solar**	**Gas**	**Energy Transition**	**Total**
Gross installed capacity (MW)	**834**	**764**	**3,650**	**—**	**5,248**	834	766	1,963	—	3,563
Total production[1] (GWh)	**345**	**557**	**2,293**	**—**	**3,195**	313	494	2,366	—	3,173
Contract production (GWh)	**—**	**262**	**1,370**	**—**	**1,632**	—	239	608	—	847
Merchant production (GWh)	**345**	**295**	**923**	**—**	**1,563**	313	255	1,758	—	2,326
Purchased power (GWh)	**—**	**—**	**(307)**	**—**	**(307)**	—	—	(218)	—	(218)
Hedged production (GWh)	**276**	**38**	**1,959**	**—**	**2,273**	84	36	1,788	—	1,908
Production contracted or hedged (%)	**80%**	**54%**	**145%**	**—%**	**122%**	27%	56%	101%	—%	87%
Hedged production as a percentage of gross installed capacity (%)	**15%**	**2%**	**25%**	**—%**	**20%**	5%	2%	42%	—%	25%
Adjusted revenues[2][3] ($)	**62**	**28**	**226**	**2**	**318**	103	38	236	1	378
Fuel ($)	**1**	**4**	**99**	**—**	**104**	2	3	86	—	91
Purchased power ($)	**3**	**1**	**11**	**—**	**15**	3	1	24	—	28
Carbon compliance[3] ($)	**—**	**1**	**36**	**—**	**37**	—	—	36	—	36
Adjusted gross margin[2] ($)	**58**	**22**	**80**	**2**	**162**	98	34	90	1	223

(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. During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions. Therefore, the Company has applied this composition to all previously reported periods.

(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 Non-IFRS and Supplementary Financial Measures section of this MD&A.

(4) Gross installed capacity for Alberta facilities in 2025 includes 1,687 MW from the acquisition of Heartland and excludes production from the Planned Divestitures.

Total production for the Alberta portfolio for the three months ended March 31, 2025, was 3,195 GWh, compared to 3,173 GWh in the same period of 2024. The increase of 22 GWh, or one per cent, was primarily due to:

- Higher contract production in the Gas segment due to the addition of gas facilities from the acquisition of Heartland in the fourth quarter of 2024;
- Higher production volumes in the Wind and Solar segment due to higher wind resources in the first quarter of 2025; and
- Higher production from the Hydro segment due to higher water resource compared to the prior year; partially offset by
- Lower merchant production in the Gas segment due to higher dispatch optimization driven by lower market prices.

Hedged production for the three months ended March 31, 2025, increased compared to the same period in 2024. In anticipation of the risk of lower prices in 2025, 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.

Adjusted gross margin for the Alberta portfolio for the three months ended March 31, 2025, was $162 million, compared to $223 million in the same period of 2024. The decrease of $61 million, or 27 per cent, was primarily due to:

- The impact of lower Alberta spot prices and ancillary services prices;
- Higher fuel costs in the Gas segment due to higher natural gas prices and the addition of the Heartland facilities; and
- An increase in the carbon price per tonne from $80 in 2024 to $95 in 2025; partially offset by
- Higher gains realized on financial hedges settled in the period;
- Positive contribution from the addition of the Heartland facilities in the Gas segment;
- Lower purchased power due to lower Alberta spot prices;
- Lower carbon compliance costs due to lower production in the Gas segment; and
- Higher hydro ancillary services volumes due to increased demand by the AESO.

The following table provides information for the Company's Alberta electricity portfolio:

3 months ended March 31	2025	2024
Alberta Market		
Spot power price average per MWh	**40**	99
Natural gas price (AECO) per GJ	**2.03**	1.94
Carbon compliance price per tonne	**95**	80
Alberta Portfolio Results		
Realized merchant power price per MWh(1)	**122**	119
Hydro energy spot power price per MWh	**70**	152
Hydro ancillary services price per MWh	**28**	54
Wind energy spot power price per MWh	**20**	51
Gas spot power price per MWh	**56**	118
Hedged power price average per MWh(2)	**71**	88
Hedged volume (GWh)	**2,273**	1,908
Fuel cost per MWh(3)	**45**	38
Carbon compliance per MWh(4)	**16**	15

(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 a supplementary financial measure and is calculated on production from carbon-emitting generation in the Gas and Energy Transition segments.

(4) Carbon compliance per MWh is a supplementary financial measure and 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 March 31, 2025, decreased from $99 per MWh in 2024 to $40 per MWh in 2025, primarily due to milder weather and the addition of increased supply from new renewables and combined-cycle gas facilities into the market compared to the same period in 2024.

The realized merchant power price per MWh of production for the Alberta portfolio for the three months ended March 31, 2025, increased by $3 per MWh, compared to the same period in 2024, primarily due to:

- Favourable hedge positions settling in the quarter, which generated positive contributions over settled spot prices in Alberta; partially offset by
- Lower average spot power prices as explained above.

Fuel cost per MWh for the three months ended March 31, 2025, increased by $7 per MWh, compared to the same period in 2024, primarily due to higher natural gas prices.

Carbon compliance cost per MWh of production for the three months ended March 31, 2025, increased by $1 per MWh, compared to the same period in 2024, primarily due to an increase in carbon pricing from $80 per tonne in 2024 to $95 per tonne in 2025.

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.

	Q2 2024	Q3 2024	Q4 2024	Q1 2025
Revenues	582	638	678	**758**
Carbon compliance	(8)	41	39	**49**
OM&A	144	143	234	**173**
Depreciation and amortization	131	133	143	**146**
Earnings (loss) before income taxes	94	9	(51)	**49**
Net earnings (loss) attributable to common shareholders	56	(36)	(65)	**46**
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	0.18	(0.12)	(0.22)	**0.15**
Cash flow from operating activities	108	229	215	**7**

	Q2 2023	Q3 2023	Q4 2023	Q1 2024
Revenues	625	1,017	624	947
Carbon compliance	25	28	27	40
OM&A	134	131	150	134
Depreciation and amortization	173	140	132	124
Earnings (loss) before income taxes	79	453	(35)	267
Net earnings (loss) attributable to common shareholders	62	372	(84)	222
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	0.23	1.41	(0.27)	0.72
Cash flow from operating activities	11	681	310	244

(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; 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 the first quarter of 2025 and 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 the first quarter of 2025 and 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.

Carbon compliance costs have been impacted by:

- Higher costs of carbon per tonne. In 2025, the cost of carbon is $95 per tonne as compared to $80 per tonne in 2024; 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 spending to support strategic and growth initiatives in the first quarter of 2025 and in all four quarters of 2024, compared to same periods in the prior year;
- Return to service of Kent Hills wind facilities and the addition of the Horizon Hill and White Rock wind facilities;
- The addition of the Heartland facilities and associated corporate costs in the first quarter of 2025 and fourth quarter of 2024;
- Higher costs stemming from planning and design work on a planned upgrade to our ERP system in the first quarter of 2025 and all quarters of 2024; 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;
- An increase in depreciation due to the addition of the White Rock wind facilities in the first quarter of 2024, and Horizon Hill wind facilities in the second quarter of 2024; and
- The acquisition of Heartland in the fourth quarter of 2024.

Higher asset impairment charges due to:

- An impairment charge on the Planned Divestiture assets classified as held for sale in the first quarter of 2025;
- Development projects that are no longer proceeding in the first quarter of 2025 and 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;
- Changes in the expected timing of when decommissioning occurs, impacting the calculation of decommissioning provision in the third quarter of 2023 and the third and fourth quarters of 2024; and
- Impairment reversal related to certain energy transition assets reclassified to assets held for sale in the first quarter of 2025.

Earnings (loss) before income taxes has been impacted by the following:

- The items described above;
- Fair value change in contingent consideration payable in the first quarter of 2025 driven by updated expectations of the fair value less costs to sell on the Planned Divestitures; and
- Higher interest expense due to lower capitalized interest during the current period as compared to the same period in 2024 resulting from lower capital activity in the first quarter of 2025 compared to the first quarter in 2024.

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 first quarter of 2025 and the second quarters of 2024 and 2023 due to timing of cash receipts, payables and accrued liabilities, higher collateral provided in the Energy Marketing segment due to unfavourable changes in market prices, and higher prepaid expense due to insurance driven timing of payments;
- Higher unrealized foreign exchange gains in all quarters of 2024 compared to the same periods in 2023; and
- Higher provisions and other non-cash items.

Strategic Priorities

Our 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 a diverse fleet of renewable facilities, 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 our 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

Our growth plan is guided by a technology-agnostic approach, focusing on our core operating jurisdictions and clear target customer segments within them.

In the first quarter of 2025, the Company made a strategic investment in Nova. Our investment in Nova aligns the Company with a world-class developer, accelerating our ability to advance our greenfield growth while executing on our other strategic priorities. The investment is structured so that it provides competitive differentiation in our U.S. development activities, while also delivering a novel structure that balances upside participation with down-side risk management. This investment provides the Company exclusive rights to Nova's late-stage development projects in the western U.S.

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 $1.5 billion in liquidity as of March 31, 2025, 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 our confidence in the business, the annual common share dividend was increased by eight per cent to $0.26 per share, our sixth consecutive annual 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.

Lead in 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 AESO 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

Over the course of 2024, we refined our development pipeline to align with evolving regulatory and interconnection dynamics, while progressing opportunities at our legacy assets. The pipeline now includes 530 MW of mid-stage projects and 4,288 MW of early-stage projects.

We remain focused on the redevelopment of existing thermal sites and pursuing greenfield and M&A opportunities in Alberta, Western Australia, and the western United States.

Early-Stage Development

Project feasibility is evaluated through initial assessments including market, technical, land and permitting evaluations. Milestones include securing key landowner control, establishment of on-site resource measurement and initial stakeholder consultations. Projects are advance to mid-stage development if a viable economic development path is identified.

The following table shows the pipeline of future growth projects currently under early-stage development:

Early-Stage Projects (MW)	Thermal Generation	Wind	Solar	Storage	Total
Various	1,445	1,213	230	1,400	4,288

Mid-Stage Development

Project scope and commercial structure are matured. Key milestones include finalizing core technologies and location, securing full land control, initiating offtake and interconnection negotiations, advancing environmental and regulatory applications, and preparing a Class 4 capital cost estimate. Successful mid-stage completion positions projects for detailed definition to support a final investment decision.

The following table shows the pipeline of future growth projects currently under mid-stage development:

Mid-Stage Projects (MW)	Thermal Generation	Wind	Solar	Storage	Total
Canada	—	100	—	—	100
United States	—	185	195	—	380
Western Australia	—	—	50	—	50
Total	—	285	245	—	530

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)	Status
Western Australia										
Mount Keith West Network Upgrade	Transmission	WA	n/a	AU$37	—	AU$40	AU$26	Q4 2025	13	• Engineering completed • Site works commenced • On track to be completed on schedule
Total[(1)]			**n/a**	**$34**	**—**	**$36**	**$24**			

(1) Total estimated spend was converted using a Canadian dollar forward exchange rate for 2025. Spent to date was converted using the period-end closing rate.

Financial Position

The following table highlights significant changes in the Condensed Consolidated Statements of Financial Position from Dec. 31, 2024 to March 31, 2025:

	March 31, 2025	Dec. 31, 2024	Increase/(decrease)
Assets			
Current assets			
Cash and cash equivalents	**238**	337	(99)
Restricted Cash	**51**	69	(18)
Trade and other receivables	**873**	767	106
Prepaid expenses and other	**91**	68	23
Risk management assets	**297**	318	(21)
Other current assets[1]	**210**	214	(4)
Total current assets	**1,760**	1,773	(13)
Non-current assets			
Risk management assets	**110**	93	17
Property, plant and equipment, net	**5,918**	6,020	(102)
Long-term financial assets	**105**	—	105
Other non-current assets[2]	**1,590**	1,613	(23)
Total non-current assets	**7,723**	7,726	(3)
Total assets	**9,483**	9,499	(16)
Liabilities			
Current liabilities			
Accounts payable, accrued liabilities and other current liabilities	**751**	756	(5)
Credit facilities, long-term debt and lease liabilities	**178**	572	(394)
Contingent consideration payable	**48**	81	(33)
Other current liabilities[3]	**1,109**	1,160	(51)
Total current liabilities	**2,086**	2,569	(483)
Non-current liabilities			
Credit facilities, long-term debt and lease liabilities	**3,699**	3,236	463
Decommissioning and other provisions (long-term)	**856**	850	6
Risk management liabilities (long-term)	**336**	305	31
Defined benefit obligation and other long-term liabilities	**190**	202	(12)
Deferred income tax liabilities	**466**	470	(4)
Other non-current liabilities[4]	**25**	24	1
Total non-current liabilities	**5,572**	5,087	485
Total liabilities	**7,658**	7,656	2
Equity			
Equity attributable to shareholders	**1,732**	1,746	(14)
Non-controlling interests	**93**	97	(4)
Total equity	**1,825**	1,843	(18)
Total liabilities and equity	**9,483**	9,499	(16)

(1) Other current assets is a supplementary financial measure and consists of inventory of $133 million (Dec. 31, 2024 — $134 million) and assets held for sale of $77 million (Dec. 31, 2024 — $80 million).

(2) Other non-current assets is a supplementary financial measure and consists of long-term portion of finance lease receivables of $297 million (Dec. 31, 2024 — $305 million), right-of-use assets of $120 million (Dec. 31, 2024 — $120 million), intangible assets of $278 million (Dec. 31, 2024 — $281 million), goodwill of $517 million (Dec. 31, 2024 — $517 million), deferred income tax assets of $55 million (Dec. 31, 2024 — $52 million), investments of $147 million (Dec. 31, 2024 — $159 million) and other assets of $176 million (Dec. 31, 2024 — $179 million).

(3) Other current liabilities is a supplementary financial measure and consists of bank overdraft of nil (Dec. 31, 2024 — $1 million), current portion of decommissioning and other provisions of $87 million (Dec. 31, 2024 — $83 million), risk management liabilities of $235 million (Dec. 31, 2024 — $277 million), dividend payable of $37 million (Dec. 31, 2024 — $49 million) and exchangeable securities of $750 million (Dec. 31, 2024 — $750 million).

(4) Other non-current liabilities is a supplementary financial measure and consists of contract liabilities $25 million (Dec. 31, 2024 — $24 million).

Significant changes in TransAlta's condensed consolidated statements of financial position were as follows:

Working Capital

The deficit of current assets over current liabilities, including the current portion of long-term debt and lease liabilities, was $326 million as at March 31, 2025 (Dec. 31, 2024 — deficit of current assets over current liabilities of $796 million). The deficit decreased primarily as a result of a decrease in the current portion of credit facilities, long-term debt and lease liabilities. On March 25, 2025, the Company repaid its $400 million variable rate term loan facility in advance of the scheduled maturity date of Sept. 7, 2025, with the proceeds received from the $450 million senior notes offering.

Current assets decreased by $13 million to $1,760 million as at March 31, 2025, from $1,773 million as at Dec. 31, 2024, primarily due to:

- Lower cash and cash equivalents mainly due to higher cash used in investing activities; and
- Lower restricted cash balance related to OCP bonds, which is required to be held in debt service account in the third and fourth quarters of the year; partially offset by
- Higher trade receivables, mainly due to timing of cash receipts and higher collateral provided in the Energy Marketing segment due to unfavourable changes in market prices;
- Higher prepaid expenses and other mainly due to prepaid insurance driven by the timing of the payments made; and
- Higher risk management assets mainly due to changes in market pricing across multiple markets driven by higher volatility.

Current liabilities decreased by $483 million from $2,569 million as at Dec. 31, 2024, to $2,086 million as at March 31, 2025, mainly due to:

- Lower current portion of credit facilities, long-term debt and lease liabilities mainly due to advance repayment of variable rate term loan facility;
- Lower contingent consideration payable related to the Planned Divestitures due to changes in fair value; and
- Lower accounts payable, accrued liabilities and other current liabilities mainly due to lower cost accruals and lower capital spend, lower income taxes payable due to lower earnings in the current period, partially offset by higher collateral received.

Non-Current Assets

Non-current assets as at March 31, 2025, were $7,723 million, consistent with $7,726 million as at Dec. 31, 2024, primarily due to:

- Lower property, plant and equipment (PP&E) resulting from depreciation of $137 million for the first quarter of 2025; partially offset by capital additions of $32 million related to major maintenance at our Canadian gas facilities; partially offset by
- Higher long-term financial assets due a term loan and a revolving facility made to Nova, a developer of renewable energy projects; and
- Higher risk management assets due to favourable changes in market prices across multiple markets.

Non-Current Liabilities

Non-current liabilities as at March 31, 2025 were $5,572 million, an increase of $485 million from $5,087 million as at Dec. 31, 2024, mainly due to:

- Increase in credit facilities, long-term debt and lease liabilities due to the $450 million senior notes offering on March 24, 2025 with an annual fixed coupon rate of 5.625, maturing on March 24, 2032; and
- Higher risk management liabilities due to forward price changes and volatility in market pricing across multiple markets.

Total Equity

As at March 31, 2025, a decrease in total equity of $18 million was due to:

- Dividends declared on common and preferred shares of $20 million;
- Provision for repurchase of common shares under the ASPP of $20 million; and
- Net losses on derivatives designated as cash flow hedges of $10 million; partially offset by
- Net earnings of $42 million.

Financial Capital

The Company is focused on maintaining a strong balance sheet and financial position to ensure access to sufficient financial capital.

Capital Structure

Our capital structure consists of the following components as shown below:

	March 31, 2025		Dec. 31, 2024	
	$	%	$	%
Net senior unsecured debt				
Recourse debt - CAD debentures	**697**	**11**	251	4
Recourse debt - U.S. senior notes	**990**	**16**	995	16
Credit facilities	**197**	**3**	543	9
Less: Cash and cash equivalents	**(238)**	**(4)**	(337)	(6)
Add: Bank overdraft	**—**	**—**	1	—
Less: Fair value of foreign exchange forward contracts on foreign-currency denominated debt(1)	**(6)**	**—**	(7)	—
Exchangeable debentures	**350**	**6**	350	6
Non-recourse debt				
TAPC Holdings LP bond (Poplar Creek)	**73**	**1**	75	1
Pingston bond	**39**	**1**	39	1
Melancthon Wolfe Wind LP bond	**133**	**2**	133	2
New Richmond Wind LP bond	**94**	**2**	93	2
Kent Hills Wind LP bond	**180**	**3**	179	3
Windrise Wind LP bond	**154**	**2**	157	3
TEC Hedland PTY Ltd bond	**671**	**11**	675	11
Heartland term facility	**224**	**4**	224	4
Recourse debt				
TransAlta OCP LP bond	**179**	**3**	192	3
Less: TransAlta OCP LP restricted cash(2)	**—**	**—**	(17)	—
Tax equity financing	**94**	**2**	101	1
Lease liabilities	**152**	**2**	151	2
Total consolidated net debt(3)(4)(5)	**3,983**	**65**	3,798	62
Exchangeable preferred shares(5)	**400**	**6**	400	7
Equity attributable to shareholders				
Common shares	**3,163**	**51**	3,179	53
Preferred shares	**942**	**15**	942	16
Contributed surplus, deficit and accumulated other comprehensive loss	**(2,373)**	**(37)**	(2,375)	(40)
Non-controlling interests	**93**	**1**	97	2
Total capital	**6,208**	**101**	6,041	100

(1) Represents the fair value of asset (liability) of the foreign exchange forward contracts used to manage the foreign exchange exposure on foreign-currency denominated debt.

(2) 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.

(3) Total consolidated net debt represents a non-IFRS measure, is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. The most directly comparable IFRS measure is total credit facilities, long-term debt and lease liabilities $3,877 million (Dec. 31, 2024 — $3,808 million). Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A for further discussion.

(4) Tax equity financing for the Skookumchuck wind facility, an equity-accounted joint venture, is not represented in these amounts.

(5) Total consolidated net debt excludes the exchangeable preferred shares as they are considered equity with dividend payments for credit purposes.

Between 2025 and 2027, the Company has remaining a total of $638 million of scheduled debt and tax equity repayments. On March 25, 2025, the Company repaid its $400 million variable rate term loan facility in advance of the scheduled maturity date of Sept. 7, 2025, with the proceeds received from the $450 million senior notes offering. The $750 million of exchangeable securities are exchangeable after Dec. 31, 2024.

Credit Facilities

The Company's credit facilities are summarized in the table below:

As at March 31, 2025		Utilized			
Credit facilities	**Facility size**	**Outstanding letters of credit[1]**	**Cash drawings**	**Available capacity**	**Maturity date**
Committed					
Syndicated credit facility	1,950	372	199	1,379	Q2 2028
Bilateral credit facilities	240	167	—	73	Q2 2026
Heartland credit facilities	276	26	224	26	Q4 2027
Heartland Export Development Canada letter of credit facility	30	14	—	16	Q4 2025
Total Committed	**2,496**	**579**	**423**	**1,494**	
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.

Credit facilities are the primary source of short-term liquidity after internally generated cash flow. The Company is in compliance with the terms of its 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 which are fully backstopped, thereby reducing the available capacity on the committed credit facilities. In addition to the net $1.3 billion of committed capacity available under the credit facilities, the Company had $238 million of available cash and cash equivalents as at March 31, 2025.

TransAlta's debt has terms and conditions, including financial covenants, that are considered ordinary and customary. As at March 31, 2025, the Company was in compliance with all of its debt covenants.

Senior Notes Offering

On March 24, 2025, the Company issued $450 million of senior notes with a fixed annual coupon of 5.625 per cent, maturing on March 24, 2032. The notes are unsecured and rank equally in right of payment with all existing and future senior indebtedness and senior in right of payment to all future subordinated indebtedness. Interest payments on the notes are made semi-annually, on March 24 and Sept. 24, with the first payment commencing Sept. 24, 2025.

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 first quarter of 2025.

At March 31, 2025, $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.

Returns to Providers of Capital

Interest Income and Interest Expense

Interest income and the components of interest expense are shown below:

3 months ended March 31	2025	2024
Interest income	**5**	7
Interest on debt	**51**	49
Interest on exchangeable debentures	**6**	7
Interest on exchangeable preferred shares	**7**	7
Capitalized interest	**—**	(14)
Interest on lease liabilities	**5**	2
Credit facility fees, bank charges and other interest	**9**	6
Accretion of provisions	**15**	12
Interest expense	**93**	69

Interest income was lower due to lower average cash balances and lower interest rates. Interest expense was higher than in the same period of 2024, primarily due to lower capitalized interest resulting from lower construction activity in the first quarter of 2025 compared to the same period in 2024.

Share Capital

The following tables outline the common and preferred shares issued and outstanding:

	Number of shares (millions)		
As at	**May 6, 2025**	**March 31, 2025**	**Dec. 31, 2024**
Common shares issued and outstanding, end of period	**296.4**	**296.6**	297.5
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

As at March 31, 2025, the Company owned 50.01 per cent of TransAlta Cogeneration, LP (TA Cogen) (March 31, 2024 — 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 March 31, 2025, the Company owned 83 per cent of Kent Hills Wind LP (March 31, 2024 — 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.

The reported net earnings attributable to non-controlling interests for the three months ended March 31, 2025, decreased by $20 million, compared to the same period in 2024, 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.

Cash Flows

Cash and cash equivalents for the three months ended March 31, 2025, decreased by $181 million, compared to the same period in 2024. On Dec. 4, 2024, the Company completed the acquisition of Heartland. 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.

The following table highlights significant changes in the Condensed Consolidated Statements of Cash Flows for the three months ended March 31, 2025 and March 31, 2024:

3 months ended March 31	2025	2024	Increase/ (decrease)
Cash and cash equivalents, beginning of period	**337**	348	(11)
Provided by (used in):			
Operating activities	**7**	244	(237)
Investing activities	**(144)**	(58)	(86)
Financing activities	**38**	(114)	152
Translation of foreign currency cash	**—**	(1)	1
Cash and cash equivalents, end of period	**238**	419	(181)

Cash Flow from Operating Activities

Cash from operating activities for the three months ended March 31, 2025, decreased compared with the same period in 2024, primarily due to the following:

	3 months ended March 31
Cash flow from operating activities for the three months ended March 31, 2024	244
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.	(39)
Higher OM&A due to increased spending on strategic and growth initiatives, the addition of the Heartland facilities and associated corporate costs, the addition of the White Rock and Horizon Hill wind facilities in the first and second quarters of 2024 and higher spending related to the planning and design of an upgrade to our ERP system.	(39)
Lower current income tax expense due to lower earnings before income taxes in the first quarter of 2025 compared to 2024.	14
Higher interest expense primarily due to lower capitalized interest resulting from lower construction activity in the first quarter of 2025 compared to 2024.	(16)
Unfavourable change in non-cash operating working capital balances due to lower accounts payable and accrued liabilities, higher accounts receivable, higher income taxes receivable and higher collateral provided.	(124)
Other non-cash items	(33)
Cash flow from operating activities for the three months ended March 31, 2025	**7**

Cash Flow used in Investing Activities

Cash used in investing activities for the three months ended March 31, 2025, increased compared with the same period in 2024, primarily due to the following:

	3 months ended March 31
Cash flow used in investing activities for the three months ended March 31, 2024	(58)
Lower additions to PP&E due to larger construction program in the first quarter of 2024 compared to the current period.	36
Favourable change in non-cash investing working capital balances due to lower capital accruals.	8
Long-term financial assets were issued during the first quarter of 2025.	(106)
Other[1]	(24)
Cash flow used in investing activities for the three months ended March 31, 2025	**(144)**

(1) Mainly comprised of the decrease in the restricted cash balance, loan receivable payments and other investing items.

Cash Flow from Financing Activities

Cash used in financing activities for the three months ended March 31, 2025, decreased compared with the same period in 2024, primarily due to the following:

	3 months ended March 31
Cash flow used in financing activities for the three months ended March 31, 2024	(114)
Repayment of the $400 million variable rate term loan facility.	(347)
Lower distributions paid to non-controlling interests due to lower net earnings in the current period.	19
Lower repurchases of common shares under the NCIB in the first quarter of 2025.	29
Issuance of $450 million senior notes during the first quarter of 2025.	450
Other	1
Cash flow from financing activities for the three months ended March 31, 2025	**38**

Other Consolidated Analysis

Commitments

The Company has not incurred any additional contractual commitments in the three months ended March 31, 2025, either directly or through its interests in joint operations and joint ventures. There were reductions to the expected future payments under the Company's long-term service agreements in the three months ended March 31, 2025.

For the approximate future payments under the long-term service agreements as at March 31, 2025, refer to Note 17 in the unaudited interim condensed consolidated financial statements as at and for the three months ended March 31, 2025.

Natural Gas Transportation 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 160 TJ per day on average and up to approximately 450 TJ per day during peak periods, while remarketing the excess capacity.

The Company may be required to recognize the natural gas transportation agreements as onerous contracts if any of the related facilities are retired in advance of the maturity of the transportation contracts.

Contingencies

For the current material outstanding contingencies, please refer to Note 37 of the 2024 audited annual consolidated financial statements. There were no material changes to the contingencies in the three months ended March 31, 2025.

Financial Instruments

Refer to Note 14 of the notes to the audited annual 2024 consolidated financial statements and Note 11 of our unaudited interim condensed consolidated financial statements as at and for the three months ended March 31, 2025, for details on Financial instruments.

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 unaudited interim condensed consolidated financial statements.

At March 31, 2025, Level III instruments had a net assets carrying value of $150 million (Dec. 31, 2024 – net liabilities $234 million). The Level III assets increased during the first quarter of 2025 from Level III liabilities as at Dec. 31, 2024 due to an increase in long-term financial assets as a result of the Company making available a term loan and revolving facility to a developer of renewable energy projects, and a change in the fair value of contingent consideration payable driven by updated expectations on the fair value less costs to sell on the Planned Divestitures. Our risk management profile and practices have not changed materially from Dec. 31, 2024.

Additional Non-IFRS and Supplementary Financial Measures

We use a number of financial measures to evaluate our performance and the performance of our business segments, including measures and ratios that 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.

We calculate adjusted measures by adjusting certain IFRS measures for certain items we believe are not reflective of our ongoing operations in the period. Except as otherwise described, these adjusted measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, unless stated otherwise.

Non-IFRS Financial Measures

Adjusted EBITDA, adjusted revenues, adjusted fuel and purchased power, adjusted gross margin, adjusted OM&A, adjusted net other operating income, adjusted earnings (loss) before income taxes, adjusted net earnings (loss) after income taxes attributable to common shareholders, FFO, FCF, total consolidated net debt, adjusted net debt and net interest expense 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.

During the first quarter of 2025, our adjusted EBITDA composition was amended to remove the impact of realized gain (loss) on closed exchange positions, which was included in adjusted EBITDA composition until the fourth quarter of 2024. The adjustment was intended to explain a timing difference between our internally and externally reported results and was useful at a time when markets were more volatile. The impact of realized gain (loss) on closed exchange positions was removed to simplify our reporting. Accordingly, the Company has applied this composition to all previously reported periods.

During the first quarter of 2025, our adjusted EBITDA composition was amended to remove the impact of Australian interest income, which was included in adjusted EBITDA composition until the fourth quarter of 2024. Initially, on the commissioning of the South Hedland facility in July 2017, we prepaid approximately $74 million of electricity transmission and distribution costs. Interest income, which was recorded on the prepaid funds, was reclassified as a reduction in the transmission and distribution costs expensed each period to reflect the net cost to the business. The impact of Australian interest income was removed to simplify our reporting since the amounts were not material. Accordingly, the Company has applied this composition to all previously reported periods.

Interest, taxes, depreciation and amortization are not included, as differences in accounting treatment 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 to arrive at the non-IFRS measures:

Adjusted Revenue

Adjusted Revenues is Revenues (the most directly comparable IFRS measure) adjusted to exclude:

- The impact of unrealized mark-to-market gains or losses and unrealized foreign exchange gains or losses on commodity transactions.
- Certain assets that we own in Canada and 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.
- Revenues from the Planned Divestitures as they do not reflect ongoing business performance.

Adjusted Fuel and Purchased Power

Adjusted Fuel and Purchased Power is Fuel and Purchased Power (the most directly comparable IFRS measure) adjusted to exclude fuel and purchased power from the Planned Divestitures as it does not reflect ongoing business performance.

Adjusted OM&A

Adjusted OM&A is OM&A (the most directly comparable IFRS measure) adjusted to exclude:

- Acquisition-related transaction and restructuring costs, mainly comprised of severance, legal and consultant fees as these do not reflect ongoing business performance.
- ERP integration costs representing planning, design and integration costs of upgrades to the existing ERP system as they represent project costs that do not occur on a regular basis, and therefore do not reflect ongoing performance.
- OM&A from the Planned Divestitures as it does not reflect ongoing business performance.

Adjusted Net Other Operating Income

Adjusted Net Other Operating Income is Net Other Operating Income (the most directly comparable IFRS measure) adjusted to exclude:

- Insurance recoveries related to the Kent Hills replacement costs of the tower collapse as these relate to investing activities and are not reflective of ongoing business performance.

Adjustments to Earnings (Loss) in Addition to Interest, Taxes, Depreciation and Amortization

- Fair value change in contingent consideration payable is not included as it is not reflective of ongoing business performance.
- 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 adjusted EBITDA for 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 adjusted EBITDA of other equity-accounted investments in our total adjusted EBITDA as it does not represent our regular power-generating operations.

Adjusted Earnings (Loss) before income taxes

Adjusted earnings (loss) before income taxes represents segmented earnings (loss) adjusted for certain items that we believe do not reflect ongoing business performance and is an important metric for evaluating performance trends in each segment.

For details of the adjustments made to earnings (loss) before income taxes (the most directly comparable IFRS measure) to calculate adjusted earnings (loss) before income taxes, refer to the Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segment section of this MD&A.

Adjusted Net Earnings (Loss) attributable to common shareholders

Adjusted net earnings (loss) attributable to common shareholders represents net earnings (loss) attributable to common shareholders adjusted for specific reclassifications and adjustments and their tax impact, and is an important metric for evaluating performance. For details of the reclassifications and adjustments made to net earnings (loss) attributable to common shareholders (the most directly comparable IFRS measure), please refer to the reconciliation of net earnings (loss) to adjusted net earnings (loss) attributable to common shareholders in the Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segment section of this MD&A.

Adjusted Net Earnings (Loss) per common share attributable to common shareholders

Adjusted net earning (loss) per common share attributable to common shareholders is calculated as adjusted net earnings (loss) attributable to common shareholders divided by a weighted average number of common shares outstanding during the period. The measure is useful in showing the earnings per common share for our core operational results as it excludes the impact of items that do not reflect an ongoing business performance. Adjusted net earnings (loss) attributable per common share is a non-IFRS ratio and the most directly comparable IFRS measure is net income (loss) per common share attributable to common shareholders. Refer to the reconciliation of earnings (loss) before income taxes to adjusted net earnings (loss) attributable to common shareholders in the Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segment section of this MD&A.

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 Operating Activities (the most directly comparable IFRS measure) to calculate FFO, refer to the Reconciliation of Cash Flow from Operations to FFO and FCF section of this MD&A.

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 costs associated with acquisition-related transaction and restructuring costs that are not reflective of ongoing operations.
- Penalties totalling $33 million were issued by the Alberta Market Surveillance Administrator for self-reported contraventions pertaining to ancillary services provided during 2021 and 2022 at our Brazeau hydro facility. The penalties were recognized in OM&A during the fourth quarter of 2024 and paid during the first quarter of 2025, and have been excluded from FFO composition as they are not reflective of ongoing business performance.
- 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 debt repayments, repay maturing debt, pay common share dividends or repurchase common shares and provides the ability to evaluate cash flow trends in comparison with the results from prior periods. Changes in working capital are excluded so that 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 Operating Activities (the most directly comparable IFRS measure) to calculate FCF, refer to the Reconciliation of Cash Flow from Operations to FFO and FCF section of this MD&A.

Adjusted Net Debt

Adjusted net debt is calculated as a sum of current and non-current portions of credit facilities, long-term debt and lease liabilities, exchangeable debentures, 50 per cent of issued preferred shares and exchangeable preferred shares, less cash and cash equivalents, less principal portion of TransAlta OCP restricted cash and fair value of hedging instruments on debt. Presenting this item from period to period provides management and investors with the ability to evaluate leverage trends more readily in comparison with prior periods' results. The most directly comparable IFRS measure is total credit facilities, long-term debt and lease liabilities.

Total Consolidated Net Debt

Total consolidated debt is calculated as a sum of current and non-current portions of credit facilities, long-term debt and lease liabilities, exchangeable debentures, less principal portion of TransAlta OCP restricted cash. Total consolidated net debt excludes the exchangeable preferred shares as they are considered equity with dividend payments for credit purposes. Presenting this item from period to period provides management and investors with the ability to evaluate leverage trends more readily in comparison with prior periods' results. The most directly comparable IFRS measure is total credit facilities, long-term debt and lease liabilities, for reconciliation refer to Financial Capital section of this MD&A.

Net Interest Expense

Net interest expense is calculated as total interest expense less total interest income and non-cash items. For detailed calculation refer to the table in the Reconciliation of Adjusted EBITDA to FFO and FCF section of this MD&A. Net Interest expense is a proxy for the actual cash interest paid that approximates the cash outflow in the FFO and FCF calculation. The most directly comparable IFRS measure is total interest expense.

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 IFRS 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 this 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

- Available liquidity
- Sustaining capital expenditures
- Growth and development expenditures
- Alberta Hydro ancillary services revenues (total and revenues per MWh)
- Alberta Hydro Assets revenues (total and revenues per MWh)
- Other Hydro Assets revenues
- Other Hydro revenues
- Highvale mine reclamation spend
- Centralia mine reclamation spend
- The Alberta electricity portfolio metrics
- Fuel cost per MWh
- Carbon compliance per MWh
- Other current assets
- Other non-current assets
- Other current liabilities
- Other non-current liabilities

Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segment

The following table reflects adjusted EBITDA and adjusted earnings (loss) before income taxes by segment and provides reconciliation to earnings (loss) before income taxes for the three months ended March 31, 2025:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	86	107	390	154	27	1	765	(7)	—	758
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(21)	36	(32)	(1)	1	—	(17)	—	17	—
Decrease in finance lease receivable	—	1	7	—	—	—	8	—	(8)	—
Finance lease income	—	1	5	—	—	—	6	—	(6)	—
Revenues from Planned Divestitures	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted revenue	65	145	366	153	28	1	758	(7)	7	758
Fuel and purchased power	4	10	163	98	—	2	277	—	—	277
Reclassifications and adjustments:										
Fuel and purchased power related to Planned Divestitures	—	—	(2)	—	—	—	(2)	—	2	—
Adjusted fuel and purchased power	4	10	161	98	—	2	275	—	2	277
Carbon compliance	—	1	49	—	—	(1)	49	—	—	49
Adjusted gross margin	61	134	156	55	28	—	434	(7)	5	432
OM&A	13	29	59	17	7	49	174	(1)	—	173
Reclassifications and adjustments:										
OM&A related to Planned Divestitures	—	—	(2)	—	—	—	(2)	—	2	—
ERP integration costs	—	—	—	—	—	(4)	(4)	—	4	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(4)	(4)	—	4	—
Adjusted OM&A	13	29	57	17	7	41	164	(1)	10	173
Taxes, other than income taxes	1	5	5	1	—	—	12	—	—	12
Net other operating income	—	(4)	(10)	—	—	—	(14)	—	—	(14)
Reclassifications and adjustments:										
Insurance recovery	—	2	—	—	—	—	2	—	(2)	—
Adjusted net other operating income	—	(2)	(10)	—	—	—	(12)	—	(2)	(14)
Adjusted EBITDA[2]	47	102	104	37	21	(41)	270			
Depreciation and amortization	(9)	(53)	(64)	(15)	(2)	(5)	(148)	2	—	(146)
Equity income	—	—	—	—	—	(1)	(1)	—	3	2
Interest income	—	—	—	—	—	5	5	—	—	5
Interest expense	—	—	—	—	—	(94)	(94)	1	—	(93)
Realized foreign exchange loss	—	—	—	—	—	(4)	(4)	—	—	(4)
Adjusted earnings (loss) before income taxes[2]	38	49	40	22	19	(140)	28			
Reclassifications and adjustments above	21	(36)	20	1	(1)	(8)	(3)			
Finance lease income	—	1	5	—	—	—	6	—	—	6
Skookumchuck earnings reclass to Equity income[1]	—	(3)	—	—	—	3	—	—	—	—
Fair value change in contingent consideration payable	—	—	34	—	—	—	34	—	—	34
Asset impairment (charges) reversals	—	—	(34)	24	—	(5)	(15)	—	—	(15)
Loss on sale of assets and other	—	—	—	—	—	(1)	(1)	—	—	(1)
Earnings (loss) before income taxes	59	11	65	47	18	(151)	49		—	49

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Adjusted EBITDA, adjusted earnings (loss) before income taxes are non-IFRS measures, are not defined, have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A.

The following table reflects adjusted EBITDA and adjusted earnings (loss) before income taxes by segment and provides reconciliation to earnings (loss) before income taxes for the three months ended March 31, 2024:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	112	139	433	217	52	—	953	(6)	—	947
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(5)	(21)	(91)	(6)	(3)	—	(126)	—	126	—
Decrease in finance lease receivable	—	1	4	—	—	—	5	—	(5)	—
Finance lease income	—	1	1	—	—	—	2	—	(2)	—
Unrealized foreign exchange gain on commodity	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted revenue	107	120	346	211	49	—	833	(6)	120	947
Fuel and purchased power	6	9	142	166	—	—	323	—	—	323
Carbon compliance	—	—	40	—	—	—	40	—	—	40
Adjusted gross margin	101	111	164	45	49	—	470	(6)	120	584
OM&A	13	20	46	18	10	28	135	(1)	—	134
Reclassifications and adjustments:										
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(3)	(3)	—	3	—
Adjusted OM&A	13	20	46	18	10	25	132	(1)	3	134
Taxes, other than income taxes	1	4	3	—	—	—	8	—	—	8
Net other operating income	—	(2)	(10)	—	—	—	(12)	—	—	(12)
Adjusted EBITDA[2][3]	87	89	125	27	39	(25)	342			
Depreciation and amortization	(7)	(43)	(55)	(16)	(1)	(4)	(126)	2	—	(124)
Equity income	—	—	—	—	—	(2)	(2)	—	3	1
Interest income	—	—	—	—	—	7	7	—	—	7
Interest expense	—	—	—	—	—	(69)	(69)	—	—	(69)
Realized foreign exchange gain (loss)[4]	—	—	—	—	—	(8)	(8)	—	—	(8)
Adjusted earnings (loss) before income taxes[2]	80	46	70	11	38	(101)	144			
Reclassifications and adjustments above	5	19	87	6	3	(3)	117			
Finance lease income	—	1	1	—	—	—	2	—	—	2
Skookumchuk earnings reclass to Equity income[1]	—	(3)	—	—	—	3	—	—	—	—
Asset impairment charges	—	(4)	—	3	—	—	(1)	—	—	(1)
Gain on sale of assets and other[4]	—	—	—	—	—	2	2	—	—	2
Unrealized foreign exchange gain[4]	—	—	—	—	—	3	3	—	—	3
Earnings (loss) before income taxes	85	59	158	20	41	(96)	267	—	—	267

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA, adjusted earnings (loss) before income taxes are non-IFRS measures, are not defined, have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers.

(3) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. During the second quarter of 2024, our Adjusted EBITDA composition was amended to exclude the impact of acquisition-related transaction and restructuring costs. Therefore, the Company has applied this composition to all previously reported periods. Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A.

(4) Foreign exchange loss and other of $3 million reported in the first quarter of 2024 was broken down to conform to the current period presentation.

Reconciliation of Earnings Before Income Taxes to Adjusted Net Earnings attributable to common shareholders

The following table reflects reconciliation of earnings before income taxes to adjusted earnings attributable to common shareholders for the three months ended March 31, 2025 and March 31, 2024:

	3 months ended March 31	
(in millions of Canadian dollars except where noted)	**2025**	**2024**
Earnings before income taxes	**49**	267
Income tax expense	**7**	29
Net earnings	**42**	238
Net (loss) earnings attributable to non-controlling interests	**(4)**	16
Net earnings attributable to common shareholders	**46**	222
Adjustments and reclassifications (pre-tax):		
Adjustments and reclassifications to Revenues	**(7)**	(120)
Adjustments and reclassifications to Fuel and purchased power	**2**	—
Adjustments and reclassifications to OM&A	**10**	3
Adjustments and reclassifications to Net other operating expense (income)	**(2)**	—
Fair value change in contingent consideration payable (gain)	**(34)**	—
Finance lease income	**(6)**	(2)
Asset impairment charges	**15**	1
Loss (gain) on sale of assets and other	**1**	(2)
Unrealized foreign exchange (gain)	**—**	(3)
Calculated tax recovery on adjustments and reclassifications[1]	**5**	29
Adjusted net earnings attributable to common shareholders[2]	**30**	128
Weighted average number of common shares outstanding in the period	**298**	308
Net income per common share attributable to common shareholders	**0.15**	0.72
Adjustments and reclassifications (net of tax)	**(0.05)**	(0.31)
Adjusted net earnings per common share attributable to common shareholders[2]	**0.10**	0.41

(1) Represents a theoretical tax calculated by applying the Company's consolidated effective tax rate of 23.3 per cent for the three months ended March 31, 2025 (March 31, 2024 — 23.3 per cent). The amount does not take into account the impact of different tax jurisdictions the Company's operations are domiciled and does not include the impact of deferred taxes.

(2) Adjusted net earnings attributable to common shareholders and Adjusted net earnings per common share attributable to common shareholders are non-IFRS measures, are not defined, have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. The most directly comparable IFRS measures are net earnings attributable to common shareholders and net earnings per share attributable to common shareholders, basic and diluted. Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A for more details.

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:

	3 months ended March 31	
(in millions of Canadian dollars except where noted)	**2025**	**2024**
Cash flow from operating activities[1]	**7**	244
Change in non-cash operating working capital balances	**117**	(7)
Cash flow from operations before changes in working capital	**124**	237
Adjustments		
Share of adjusted FFO from joint venture[1]	**2**	2
Decrease in finance lease receivable	**8**	5
Brazeau penalties payment	**33**	—
Acquisition-related transaction and restructuring costs	**6**	3
Other[2]	**6**	7
FFO[3]	**179**	254
Deduct:		
Sustaining capital[1]	**(23)**	1
Dividends paid on preferred shares	**(13)**	(13)
Distributions paid to subsidiaries' non-controlling interests	**—**	(19)
Principal payments on lease liabilities	**(1)**	(1)
Other	**(3)**	(1)
FCF[3]	**139**	221
Weighted average number of common shares outstanding in the period	**298**	308
FFO per share[3]	**0.60**	0.82
FCF per share[3]	**0.47**	0.72

(1) Includes our share of amounts for the Skookumchuck wind facility, an equity-accounted joint venture.

(2) Other consists of production tax credits, which is a reduction to tax equity debt, less distributions from an equity-accounted joint venture.

(3) These items are non-IFRS measures, which are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. During the second quarter of 2024, our Adjusted EBITDA composition was amended to exclude the impact of acquisition-related transaction and restructuring costs. Therefore, the Company has applied this composition to all previously reported periods. Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A.

Reconciliation of Adjusted EBITDA to FFO and FCF

The table below provides a reconciliation of our adjusted EBITDA to our FFO and FCF:

3 months ended March 31	2025	2024
Adjusted EBITDA[(1)(4)]	**270**	342
Provisions	**8**	—
Net interest expense[(2)]	**(72)**	(48)
Current income tax expense	**(13)**	(27)
Realized foreign exchange loss	**(2)**	(8)
Decommissioning and restoration costs settled	**(9)**	(7)
Other non-cash items	**(3)**	2
FFO[(3)(4)]	**179**	254
Deduct:		
Sustaining capital[(4)]	**(23)**	1
Dividends paid on preferred shares	**(13)**	(13)
Distributions paid to subsidiaries' non-controlling interests	**—**	(19)
Principal payments on lease liabilities	**(1)**	(1)
Other	**(3)**	(1)
FCF[(3)(4)]	**139**	221

(1) Adjusted EBITDA is defined in the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A and reconciled to earnings (loss) before income taxes above. During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. During the second quarter of 2024, our Adjusted EBITDA composition was amended to exclude the impact of acquisition-related transaction and restructuring costs. Therefore, the Company has applied this composition to all previously reported periods.

(2) Net interest expense is a non-IFRS measure, 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 table below for detailed calculation.

(3) These items are non-IFRS measures, 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 Non-IFRS and Supplementary Financial 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.

Net interest expense in the reconciliation of our adjusted EBITDA to our FFO and FCF is calculated as follows:

3 months ended March 31	2025	2024
Interest expense	**93**	69
Less: Interest Income	**(5)**	(7)
Less: non-cash items[(1)]	**(16)**	(14)
Net Interest Expense	**72**	48

(1) Non-cash items include accretion of provisions, financing cost amortization and other non-cash items.

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

(in millions of Canadian dollars except where noted)

As at	March 31, 2025	Dec. 31, 2024
Credit facilities, long-term debt and lease liabilities(1)	**3,877**	3,808
Exchangeable debentures	**350**	350
Less: Cash and cash equivalents	**(238)**	(337)
Add: Bank overdraft	**—**	1
Add: 50 per cent of issued preferred shares and exchangeable preferred shares(2)	**671**	671
Other(3)	**(6)**	(24)
Adjusted net debt(4)	**4,654**	4,469
Adjusted EBITDA(5)	**1,183**	1,255
Adjusted net debt to adjusted EBITDA (times)	**3.9**	3.6

(1) Consists of current and non-current portions of long-term debt, which includes lease liabilities and tax equity financing.

(2) 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.

(3) Includes principal portion of TransAlta OCP restricted cash (nil as at March 31, 2025 and $17 million as at Dec. 31, 2024) and fair value of hedging instruments on debt (included in risk management assets and/or liabilities on the Condensed Consolidated Statements of Financial Position).

(4) The tax equity financing for the Skookumchuck wind facility, an equity-accounted joint venture, is not represented in this amount. Adjusted net debt is a non-IFRS measure, 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 Non-IFRS and Supplementary Financial Measures section of this MD&A.

(5) Last four quarters.

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 March 31, 2025 was higher compared to Dec. 31, 2024, due to higher adjusted net debt resulting from lower cash balances due to higher cash flow used in investing activities and lower annualized adjusted EBITDA as at March 31, 2025 as compared to Dec. 31, 2024.

2025 Outlook

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[(2)]	2024 Actual[(3)]
Adjusted EBITDA[(1)]	$1,150 to $1,250 million	$1,253 million
FCF[(1)]	$450 to $550 million	$569 mllion
FCF per share[(1)]	$1.51 to $1.85	$1.88
Dividend per share	$0.26 annualized	$0.24 annualized

(1) These are non-IFRS measures, which are not defined, 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 Non-IFRS and Supplementary Financial Measures section of this MD&A.

(2) Represents forward-looking information.

(3) The actual 2024 amounts for the most directly comparable IFRS measures for Adjusted EBITDA and FCF were as follows: Earnings before income taxes $319 million and Cash flow from operating activities $796 million. The most directly comparable IFRS ratio to FCF per share is cash flow from operating activities per share of $2.64, which is calculated as cash flow from operating activities for the period divided by weighted average number of common shares outstanding during the period.

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
Alberta spot ($/MWh)	$40 to $60
Mid-Columbia spot (US$/MWh)	US$50 to US$70
AECO gas price ($/GJ)	$1.60 to $2.10

Alberta spot price sensitivity: a +/- $1 per MWh change in spot price is expected to have a +/-$2 million impact on adjusted EBITDA for the balance of the year.

Other assumptions relevant to the 2025 outlook

Measure	2025 Expectations
Energy Marketing gross margin	$110 to $130 million
Sustaining capital	$145 to $165 million
Current income tax expense	$95 to $130 million
Net interest expense	$255 to $275 million

Alberta Hedging

Range of hedging assumptions	Q2 2025	Q3 2025	Q4 2025	2026
Hedged production (GWh)	1,809	2,139	1,848	6,432
Hedge price ($/MWh)	$69	$68	$71	$68
Hedged gas volumes (GJ)	7 million	8 million	7 million	19 million
Hedge gas prices ($/GJ)	$3.25	$3.22	$3.57	$3.65

Refer to the 2025 Outlook section in our 2024 Annual MD&A for further details relating to our Outlook and related assumptions.

Liquidity and Capital Resources

We maintain adequate available liquidity under our committed credit facilities. As at March 31, 2025, we had access to $1.5 billion in liquidity, including $238 million in cash, which exceeds the funds required for committed growth, sustaining capital and productivity projects.

Material Accounting Policies and Critical Accounting Estimates

The preparation of unaudited interim condensed consolidated 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 these 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.

During the three months ended March 31, 2025, revisions to the fair values of Assets Held for Sale and Contingent consideration payable were made based on new information obtained during the period.

Tariffs

Throughout the first quarter of 2025, President Trump has continued to announce, implement and at times, withdraw tariffs across various sectors and countries. As of April 2, 2025, Canada-United States-Mexico Agreement (CUSMA) compliant goods are exempt from tariffs; however, they remain for non-CUSMA compliant goods, aluminum and steel imports, as well as the automotive sector. At this time, tariffs do not apply to cross border sales of electricity. If tariffs remain in effect, the Company may see an impact on the cost of materials required for ongoing operations and future growth projects. The Company continues to assess the direct and indirect impact of tariffs or other trade protectionist measures on our business.

Accounting Changes

The accounting policies adopted in the preparation of the unaudited interim condensed consolidated financial statements are consistent with those followed in the preparation of the Company's annual consolidated financial statements for the year ended Dec. 31, 2024.

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.

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.

Please refer to the Governance and Risk Management section of our 2024 Annual MD&A and Note 12 of our unaudited interim condensed consolidated financial statements for details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2024.

Regulatory Updates

Refer to the Policy and Legal Risks discussion in our 2024 Annual MD&A for further details that supplement the recent developments as discussed below:

Canada

Federal

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 government has utilized 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. As of April 1, 2025, the federal requirement for a consumer carbon price was removed; however, the requirement for industrial carbon pricing remains in place.

Canada's provinces have jurisdiction over their respective electricity sectors and play an important role in setting industrial 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.

A federal election occurred in Canada on April 28, 2025, resulting in a minority government for the Liberal Party of Canada. TransAlta will be monitoring policy developments related to our business, including but not limited to Clean Electricity Regulations, Investment Tax Credit, industrial carbon pricing, as well as funding for net-zero technologies. TransAlta continues to closely monitor the political and policy environment.

Alberta

During the first quarter of 2025, the Government of Alberta commenced consultation on the Technology Innovation and Emissions Reduction Regulation (TIER) in advance of the scheduled program review in 2026. The TIER program has been in place since 2007 and is expected to be maintained going forward.

During the first quarter of 2025, the AESO continued consultation on the proposed Restructured Energy Market (REM). The AESO's four stated objectives for the REM are: (i) a reliable electric grid; (ii) affordable electricity for consumers; (iii) decarbonization by 2050 and related policy objectives; and (iv) reasonable implementation. On April 4, 2025, the Minister of Affordability and Utilities and the AESO announced a revised proposal for the REM design, seeking to address concerns regarding the complexity, scale and timeline. TransAlta continues to assess the proposed design changes and participate in the AESO consultation process. The AESO plans to implement interim rules by the end of 2025, with REM implementation in 2027 or 2028.

United States

The President of the United States has signed a number of executive orders seeking to enable gas and coal-fired electricity in the country, as well as limiting the development of renewable electricity generation. While these initial actions were mostly directional in nature, subsequent executive orders and federal agency directives show a trend toward an eased regulatory environment that may lower fossil fuel and power-production costs. This may make investments in natural gas power plants more attractive; at the same time, a halt on federal agency wind permits may impede future offshore and land-based wind development.

Currently, federal incentives for renewable technologies remain in force through the Inflation Reduction Act (IRA) of 2022. In addition to federal actions, state and regional renewable and climate policies continue to have a significant impact on the pace of energy transition in the country. The Company continues to assess actions at all levels of government as they emerge.

Australia

On March 8, 2025, a state election occurred in Western Australia. The Labor government, led by Premier Roger Cook won a third consecutive four-year term. The re-election of the Labor government is expected to provide continued stability in the state.

The Australian federal election was held on May 3, 2025. The Labour Party secured a majority government and a second term. The results are not expected to have a significant impact on TransAlta.

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). During the three months ended March 31, 2025, 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.

Consistent with the evaluation at Dec. 31, 2024, the scope of the evaluation at March 31, 2025 does not include controls over financial reporting of the assets acquired through the Heartland acquisition on Dec. 4, 2024. Heartland's total and net assets represented approximately seven per cent and 15 per cent of the Company's total and net assets, respectively, as at March 31, 2025.

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 March 31, 2025, the end of the period covered by this MD&A, our ICFR and DC&P were effective.

Condensed Consolidated Statements of Earnings

(in millions of Canadian dollars except where noted)

	3 months ended March 31	
Unaudited	**2025**	**2024**
Revenues (Note 3)	**758**	947
Fuel and purchased power (Note 4)	**277**	323
Carbon compliance (Note 4)	**49**	40
Gross margin	**432**	584
Operations, maintenance and administration (Note 4)	**173**	134
Depreciation and amortization	**146**	124
Asset impairment charges (Note 5)	**15**	1
Taxes, other than income taxes	**12**	8
Net other operating income	**(14)**	(12)
Operating income	**100**	329
Equity income	**2**	1
Fair value change in contingent consideration payable (Note 5)	**34**	—
Finance lease income	**6**	2
Interest income	**5**	7
Interest expense (Note 6)	**(93)**	(69)
Foreign exchange loss	**(4)**	(5)
(Loss) gain on sale of assets and other	**(1)**	2
Earnings before income taxes	**49**	267
Income tax expense (Note 7)	**7**	29
Net earnings	**42**	238
Net earnings attributable to:		
Common shareholders	**46**	222
Non-controlling interests (Note 8)	**(4)**	16
	42	238
Weighted average number of common shares outstanding in the period (*millions*)	**298**	308
Net earnings per share attributable to common shareholders, basic and diluted (Note 15)	**0.15**	0.72

See accompanying notes.

Condensed Consolidated Statements of Comprehensive Income

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2025**	**2024**
Net earnings	**42**	238
Other comprehensive income		
Net actuarial gains on defined benefit plans, net of tax(1)	**—**	7
Total items that will not be reclassified subsequently to net earnings	**—**	7
(Losses) gains on translating net assets of foreign operations, net of tax	**(1)**	6
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax(2)	**1**	(10)
(Losses) gains on derivatives designated as cash flow hedges, net of tax(3)	**(1)**	46
Reclassification of (gains) losses on derivatives designated as cash flow hedges to net earnings, net of tax(4)	**(9)**	38
Total items that will be reclassified subsequently to net earnings	**(10)**	80
Other comprehensive (loss) income	**(10)**	87
Total comprehensive income	**32**	325
Total comprehensive income attributable to:		
TransAlta shareholders	**36**	309
Non-controlling interests (Note 8)	**(4)**	16
	32	325

(1) Net of income tax expense of nil for the three months ended March 31, 2025 (March 31, 2024 — $2 million expense).

(2) Net of income tax expense of nil for the three months ended March 31, 2025 (March 31, 2024 — $1 million recovery).

(3) Net of income tax expense of nil for the three months ended March 31, 2025 (March 31, 2024 — $12 million expense).

(4) Net of reclassification of income tax recovery of $2 million for the three months ended March 31, 2025 (March 31, 2024 — $10 million expense).

See accompanying notes.

Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars)

Unaudited	March 31, 2025	Dec. 31, 2024
Current assets		
Cash and cash equivalents	**238**	337
Restricted cash (Note 14)	**51**	69
Trade and other receivables (Note 9)	**873**	767
Prepaid expenses and other	**91**	68
Risk management assets (Note 11 and 12)	**297**	318
Inventory	**133**	134
Assets held for sale	**77**	80
	1,760	1,773
Non-current assets		
Investments	**147**	159
Long-term portion of finance lease receivables	**297**	305
Risk management assets (Note 11 and 12)	**110**	93
Property, plant and equipment (Note 13)	**5,918**	6,020
Right-of-use assets	**120**	120
Intangible assets	**278**	281
Goodwill	**517**	517
Deferred income tax assets	**55**	52
Long-term financial assets (Note 10)	**105**	—
Other assets	**176**	179
Total assets	**9,483**	9,499
Current liabilities		
Bank overdraft	**—**	1
Accounts payable, accrued liabilities and other current liabilities (Note 9)	**751**	756
Current portion of decommissioning and other provisions	**87**	83
Risk management liabilities (Note 11 and 12)	**235**	277
Dividends payable (Note 15 and 16)	**37**	49
Exchangeable securities	**750**	750
Contingent consideration payable	**48**	81
Current portion of credit facilities, long-term debt and lease liabilities (Note 14)	**178**	572
	2,086	2,569
Non-current liabilities		
Credit facilities, long-term debt and lease liabilities (Note 14)	**3,699**	3,236
Decommissioning and other provisions	**856**	850
Deferred income tax liabilities	**466**	470
Risk management liabilities (Note 11 and 12)	**336**	305
Contract liabilities	**25**	24
Defined benefit obligation and other long-term liabilities	**190**	202
Equity		
Common shares (Note 15)	**3,163**	3,179
Preferred shares (Note 16)	**942**	942
Contributed surplus	**29**	42
Deficit	**(2,433)**	(2,458)
Accumulated other comprehensive income	**31**	41
Equity attributable to shareholders	**1,732**	1,746
Non-controlling interests (Note 8)	**93**	97
Total equity	**1,825**	1,843
Total liabilities and equity	**9,483**	9,499

Commitments and contingencies (Note 17)

See accompanying notes.

Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

Unaudited 3 months ended March 31, 2025	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2024	**3,179**	**942**	**42**	**(2,458)**	**41**	**1,746**	**97**	**1,843**
Net earnings	**—**	**—**	**—**	**46**	**—**	**46**	**(4)**	**42**
Other comprehensive income:								
Net losses on derivatives designated as cash flow hedges, net of tax	**—**	**—**	**—**	**—**	**(10)**	**(10)**	**—**	**(10)**
Total comprehensive income	**—**	**—**	**—**	**46**	**(10)**	**36**	**(4)**	**32**
Common share dividends (Note 15)	**—**	**—**	**—**	**(20)**	**—**	**(20)**	**—**	**(20)**
Shares purchased under normal course issuer bid (NCIB) (Note 15)	**(3)**	**—**	**—**	**(1)**	**—**	**(4)**	**—**	**(4)**
Provision for repurchase of shares under the automatic securities purchase plan (ASPP) (Note 15)	**(20)**	**—**	**—**	**—**	**—**	**(20)**	**—**	**(20)**
Share-based payment plans and stock options exercised	**7**	**—**	**(13)**	**—**	**—**	**(6)**	**—**	**(6)**
Balance, March 31, 2025	**3,163**	**942**	**29**	**(2,433)**	**31**	**1,732**	**93**	**1,825**

3 months ended March 31, 2024	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, 2023	3,285	942	41	(2,567)	(164)	1,537	127	1,664
Net earnings	—	—	—	222	—	222	16	238
Other comprehensive income:								
Net losses on translating net assets of foreign operations, net of hedges and tax	—	—	—	—	(4)	(4)	—	(4)
Net gains on derivatives designated as cash flow hedges, net of tax	—	—	—	—	84	84	—	84
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	7	7	—	7
Total comprehensive income	—	—	—	222	87	309	16	325
Shares purchased under NCIB (Note 15)	(37)	—	—	5	—	(32)	—	(32)
Provision for repurchase of shares under the ASPP (Note 15)	(3)	—	—	—	—	(3)	—	(3)
Share-based payment plans and stock options exercised	13	—	(16)	—	—	(3)	—	(3)
Distributions declared to non-controlling interests (Note 8)	—	—	—	—	—	—	(19)	(19)
Balance, March 31, 2024	3,258	942	25	(2,340)	(77)	1,808	124	1,932

See accompanying notes.

Condensed Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2025**	**2024**
Operating activities		
Net earnings	**42**	238
Depreciation and amortization	**146**	124
Accretion of provisions (Note 6)	**15**	12
Decommissioning and restoration costs settled	**(9)**	(7)
Deferred income tax expense (Note 7)	**(6)**	2
Unrealized gain from risk management activities	**(12)**	(125)
Unrealized foreign exchange loss (gain)	**—**	(4)
Provisions and contract liabilities	**(32)**	—
Asset impairment charges (Note 5)	**15**	1
Equity loss, net of distributions from investments	**—**	1
Other non-cash items	**(35)**	(5)
Cash flow from operations before changes in working capital	**124**	237
Change in non-cash operating working capital balances	**(117)**	7
Cash flow from operating activities	**7**	244
Investing activities		
Additions to property, plant and equipment (Note 13)	**(32)**	(68)
Additions to intangible assets	**(2)**	(1)
Restricted cash (Note 14)	**18**	22
Loan advances	**(3)**	—
Acquisitions, net of cash acquired	**(2)**	—
Increase in Long-term financial assets (Note 10)	**(106)**	—
Proceeds on sale of property, plant and equipment	**—**	1
Decrease in finance lease receivable	**8**	5
Other	**(4)**	12
Change in non-cash investing working capital balances	**(21)**	(29)
Cash flow used in investing activities	**(144)**	(58)
Financing activities		
Net decrease in borrowings under credit facilities (Note 14)	**(347)**	—
Repayment of long-term debt (Note 14)	**(26)**	(29)
Issuance of long-term debt (Note 14)	**450**	—
Dividends paid on common shares (Note 15)	**(18)**	(17)
Dividends paid on preferred shares (Note 16)	**(13)**	(13)
Repurchase of common shares under NCIB (Note 15)	**(3)**	(32)
Proceeds on issuance of common shares (Note 15)	**—**	3
Distributions paid to subsidiaries' non-controlling interests (Note 8)	**—**	(19)
Decrease in lease liabilities	**(1)**	(1)
Financing fees and other	**(4)**	—
Change in non-cash financing working capital balances	**—**	(6)
Cash flow from (used in) financing activities	**38**	(114)
Cash flow (used in) from operating, investing and financing activities	**(99)**	72
Effect of translation on foreign currency cash	**—**	(1)
(Decrease) increase in cash and cash equivalents	**(99)**	71
Cash and cash equivalents, beginning of period	**337**	348
Cash and cash equivalents, end of period	**238**	419
Cash taxes paid	**67**	12
Cash interest paid	**64**	58
Cash interest received	**4**	6

See accompanying notes.

Notes to the Condensed Consolidated Financial Statements

(Unaudited)

(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.

B. Basis of Preparation

These unaudited interim condensed consolidated financial statements have been prepared in compliance with International Financial Reporting Standard (IFRS) and International Accounting Standard (IAS) 34 Interim Financial Reporting using the same accounting policies as those used in the Company's most recent audited annual consolidated financial statements. These unaudited interim condensed consolidated financial statements do not include all of the disclosures included in the Company's audited annual consolidated financial statements. Accordingly, they should be read in conjunction with the Company's most recent audited annual consolidated financial statements which are available on SEDAR+ at www.sedarplus.ca and on EDGAR at www.sec.gov.

The unaudited interim condensed consolidated financial statements include the accounts of the Company and the subsidiaries that it controls.

The unaudited interim condensed consolidated financial statements have been prepared on a historical cost basis except for certain financial instruments, which are stated at fair value.

These unaudited interim condensed consolidated financial statements reflect all adjustments which consist of normal recurring adjustments and accruals that are, in the opinion of management, necessary for a fair presentation of results. Interim results will fluctuate due to plant maintenance schedules, the seasonal demands for electricity and changes in energy prices. Consequently, interim condensed results are not necessarily indicative of annual results. TransAlta's results are partly seasonal due to the nature of the electricity market and related fuel costs.

These unaudited interim condensed consolidated financial statements were authorized for issue by the Audit, Finance and Risk Committee on behalf of TransAlta's Board of Directors (the Board) on May 6, 2025.

C. Significant Accounting Judgements and Key Sources of Estimation Uncertainty

The preparation of these unaudited interim condensed consolidated financial statements in accordance with IAS 34 requires management to use judgment and make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and disclosures of contingent assets and liabilities. These estimates are subject to uncertainty. Actual results could differ from these 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 unaudited interim condensed 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.

Throughout the first quarter of 2025, President Trump has continued to announce, implement and at times, withdraw tariffs across various sectors and countries. As of April 2, 2025, Canada-United States-Mexico Agreement (CUSMA) compliant goods are exempt from tariffs; however, they remain for non-CUSMA compliant goods, aluminum and steel imports, as well as the automotive sector. At this time, tariffs do not apply to cross border sales of electricity. If tariffs remain in effect, the Company may see an impact on the cost of materials required for ongoing operations and future growth projects. The Company continues to assess the direct and indirect impact of tariffs or other trade protectionist measures on our business.

During the three months ended March 31, 2025, revisions to the fair values of Assets Held for Sale and Contingent consideration payable were made based on new information obtained during the period.

Refer to Note 2(Q) of the Company's 2024 audited annual consolidated financial statements for further details on the significant accounting judgments and key sources of estimation uncertainty.

2. Accounting Changes

The accounting policies adopted in the preparation of the unaudited interim condensed consolidated financial statements are consistent with those followed in the preparation of the Company's annual consolidated financial statements for the year ended Dec. 31, 2024.

A. 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.

B. 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.

3. 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, 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.

3 months ended March 31, 2025	Hydro	Wind & Solar	Gas	Energy Transition	Energy Marketing	Corporate[1]	Total
Revenues from contracts with customers							
Power and other	5	82	162	3	4	2	258
Environmental and tax attributes[2]	10	26	7	—	—	(1)	42
Revenue from contracts with customers	15	108	169	3	4	1	300
Revenue from derivatives and other trading activities[3]	22	(33)	103	63	23	—	178
Revenue from merchant sales	47	20	115	88	—	—	270
Other[4]	2	5	3	—	—	—	10
Total revenue	86	100	390	154	27	1	758
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	10	9	7	3	—	(1)	28
Over time	5	99	162	—	4	2	272
Total revenue from contracts with customers	15	108	169	3	4	1	300

(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.

3 months ended March 31, 2024	Hydro	Wind & Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Revenues from contracts with customers							
Power and other	5	70	112	3	—	—	190
Environmental and tax attributes[1]	14	18	—	—	—	—	32
Revenue from contracts with customers	19	88	112	3	—	—	222
Revenue from derivatives and other trading activities[2]	6	21	88	70	52	—	237
Revenue from merchant sales	83	20	222	144	—	—	469
Other[3]	4	4	11	—	—	—	19
Total revenue	112	133	433	217	52	—	947
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	14	18	—	3	—	—	35
Over time	5	70	112	—	—	—	187
Total revenue from contracts with customers	19	88	112	3	—	—	222

(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 US 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. In the Gas segment, $7 million of Revenue from leases was reclassified to Other to conform to the current period presentation.

4. 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:

	2025		2024	
3 months ended March 31	Fuel and purchased power	OM&A	Fuel and purchased power	OM&A
Gas fuel costs	**142**	**—**	109	—
Coal fuel costs	**44**	**—**	34	—
Royalty, land lease, other direct costs	**6**	**—**	8	—
Purchased power	**85**	**—**	172	—
Salaries and benefits	**—**	**76**	—	65
Other operating expenses	**—**	**97**	—	69
Total	**277**	**173**	323	134

OM&A

OM&A expenses for the three months ended March 31, 2025 was $173 million (March 31, 2024 — $134 million) and included spending to support strategic and growth initiatives, spending related to the addition of the Heartland facilities and associated corporate costs and spending related to the planning and design of an upgrade to the Company's enterprise resource planning (ERP) system.

Carbon Compliance

As at March 31, 2025, the Company holds 748,537 emission credits in inventory that were purchased externally with a recorded book value of $29 million (Dec. 31, 2024 — 460,585 emission credits with a recorded book value of $18 million). The Company also has 2,123,564 (Dec. 31, 2024 — 2,109,491) of internally generated eligible emission credits from the Company's Wind and Solar and Hydro segments which 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. The compliance price of carbon for the 2024 obligation was $80 per tonne. It increased to $95 per tonne in 2025.

5. Asset Impairment Charges

The Company recognized the following asset impairment (reversals) charges:

3 months ended March 31	2025	2024
Segments:		
Energy Transition asset impairment reversal	**(31)**	—
Gas asset impairment charge	**34**	—
Changes in decommissioning and restoration provisions on retired assets[(1)]	**7**	(3)
Project development costs[(2)]	**5**	4
Asset impairment charges	**15**	1

(1) During the three months ended March 31, 2025, the Company recorded asset impairment charges due to changes in discount rates and cash flow revisions on retired assets (March 31, 2024 — reversal).

(2) During the three months ended March 31, 2025 and March 31, 2024, the Company recognized an impairment charge in the Corporate segment related to projects that are no longer proceeding.

Energy Transition Equipment Sale

On March 20, 2025, the Company entered into an agreement to sell generation equipment that had previously been impaired in the energy transition segment with closing of the sale expected during the third quarter of 2025. During the three months ended March 31, 2025, the Company recorded an asset impairment reversal of $31 million for a previously recognized impairment loss and transferred the respective generation equipment to assets held for sale.

Planned Divestiture

During the three months ended March 31, 2025, the Company recognized an impairment loss of $34 million in the gas segment on the planned divestiture of certain Heartland assets held for sale based on updated expectations of the fair value less costs to sell. A corresponding reduction in the contingent consideration payable was also recognized.

6. Interest Expense

The components of interest expense are as follows:

3 months ended March 31	2025	2024
Interest on debt	**51**	49
Interest on exchangeable debentures[(1)]	**6**	7
Interest on exchangeable preferred shares[(2)]	**7**	7
Capitalized interest (Note 13)	**—**	(14)
Interest on lease liabilities	**5**	2
Credit facility fees, bank charges and other interest	**9**	6
Accretion of provisions	**15**	12
Interest expense	**93**	69

(1) On May 1, 2019, Brookfield invested $350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039.

(2) 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. On April 23, 2025, the Company declared a dividend of $7 million in aggregate on the Series I Preferred Shares at the fixed rate of 1.726 per cent, per share, payable on June 2, 2025.

7. Income Taxes

The components of income tax expense are as follows:

3 months ended March 31	2025	2024
Current income tax expense	**13**	27
Deferred income tax (recovery) expense related to the origination and reversal of temporary differences	**(12)**	29
Write-down (reversal) of unrecognized deferred income tax assets[1]	**6**	(27)
Income tax expense	**7**	29
Current income tax expense	**13**	27
Deferred income tax (recovery) expense	**(6)**	2
Income tax expense	**7**	29

(1) During the three months ended March 31, 2025, the Company recorded a write-down of deferred tax assets of $6 million (March 31, 2024 — $27 million reversal of write-down). 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.

8. Non-Controlling Interests

The Company's subsidiaries and operations that have non-controlling interests are as follows:

Subsidiary/Operation	Non-controlling interest owner	NCI as at March 31, 2025	NCI as at Dec. 31, 2024	NCI as at March 31, 2024
TransAlta Cogeneration LP	Canadian Power Holdings Inc.	**49.99%**	49.99%	49.99%
Kent Hills Wind LP	Natural Forces Technologies Inc.	**17%**	17%	17%

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.

Summarized financial information relating to subsidiaries with significant non-controlling interests is as follows:

3 months ended March 31	2025	2024
Net earnings attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**(5)**	16
Kent Hills Wind LP	**1**	—
	(4)	16
Total comprehensive income attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**(5)**	16
Kent Hills Wind LP	**1**	—
	(4)	16
Distributions paid to non-controlling interests		
TransAlta Cogeneration L.P.	**—**	19
Kent Hills Wind LP	**—**	—
	—	19

As at	March 31, 2025	Dec. 31, 2024
Equity attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**(41)**	(46)
Kent Hills Wind LP	**(52)**	(51)
	(93)	(97)

9. Trade and Other Receivables and Accounts Payable, Accrued liabilities and Other Current Liabilities

	March 31, 2025	Dec. 31, 2024
Trade accounts receivable	**619**	570
Collateral provided (Note 12)	**148**	124
Current portion of finance lease receivables	**30**	30
Current portion of loan receivable	**—**	1
Income taxes receivable	**76**	42
Trade and other receivables	**873**	767

	March 31, 2025	Dec. 31, 2024
Accounts payable and accrued liabilities	**675**	694
Income taxes payable	**5**	23
Interest payable	**24**	17
Current portion of contract liabilities	**18**	12
Liabilities Held for Sale	**8**	1
Collateral held (Note 12)	**21**	9
Accounts payable, accrued liabilities and other current liabilities	**751**	756

10. Long-Term Financial Assets

Nova Clean Energy, LLC

During the first quarter of 2025, the Company made available a US$75 million term loan and a US$100 million revolving facility to Nova Clean Energy, LLC (Nova), a developer of renewable energy projects. As at March 31, 2025, US$25M and US$49M have been drawn from the term loan and revolving facility, respectively. These facilities are classified as financial assets measured at Fair Value Through Profit and Loss (FVTPL). The outstanding principal under the term loan and the revolving facility bear interest of seven per cent per annum with interest paid quarterly. The terms of the term loan and the revolving facility are six and five years, respectively, unless accelerated. The term loan is convertible to equity at any time at the option of the Company and any remaining unused term loan commitments at the time of conversion would be terminated. The term loan and revolving facility are subject to customary financing conditions and covenants that may restrict Nova's ability to access funds. This investment in Nova provides the Company with the exclusive right to purchase Nova's late-stage development projects in the western U.S.

11. 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.

B. Fair Value of Financial Instruments

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.

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.

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.

Other than the long-term financial assets discussed in Section IV below, there were no changes in the Company's valuation processes, valuation techniques and types of inputs used in the fair value measurements during the period. Refer to Note 14 of the 2024 audited annual consolidated financial statements for further details.

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 March 31, 2025, are as follows: Level I — $11 million net liability (Dec. 31, 2024 — $12 million net liability), Level II — $49 million net asset (Dec. 31, 2024 — $2 million net liability) and Level III — $207 million net liability (Dec. 31, 2024 — $153 million net liability).

Significant changes in commodity net risk management assets (liabilities) during the three months ended March 31, 2025, are primarily attributable volatility in market prices across multiple markets on both existing contracts and new contracts and contract settlements.

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 three months ended March 31, 2025 and 2024, respectively:

	3 months ended March 31, 2025			3 months ended March 31, 2024		
	Hedge	Non-hedge	Total	Hedge	Non-hedge	Total
Opening balance	—	(153)	(153)	—	(147)	(147)
Changes attributable to:						
Market price changes on existing contracts	—	(43)	(43)	—	62	62
Market price changes on new contracts	—	1	1	—	3	3
Contracts settled	—	(13)	(13)	—	(3)	(3)
Change in foreign exchange rates	—	1	1	—	5	5
Net risk management liabilities at end of period	—	(207)	(207)	—	(80)	(80)
Additional Level III information:						
Total (losses) gains included in earnings before income taxes	—	(41)	(41)	—	70	70
Unrealized (losses) gains included in earnings before income taxes relating to net assets (liabilities) held at period end	—	(54)	(54)	—	67	67

As at March 31, 2025, the total Level III risk management asset balance was $100 million (Dec. 31, 2024 – $110 million) and the Level III risk management liability balance was $307 million (Dec. 31, 2024 – $263 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.

Included in the Level III classification are several long-term wind energy sales, including contracts for differences and virtual power purchase agreements, that are recognized as derivatives for accounting purposes. The sensitivity reflects the potential impacts on the fair value of these long-term wind agreements. These long-term wind energy sales are backed by physical assets to effectively reduce our market risk.

As at		March 31, 2025		
Description	**Valuation technique**	**Unobservable input**	**Reasonably possible change**	**Sensitivity[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	**+44**
		Illiquid future REC[2] prices (per unit)	Price decrease of US$12 or increase of US$8	
		Wind discounts	0% decrease or 6% increase	**-32**
Long-term wind energy sale — Canada	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of $61 or increase of $10	**+72**
		Wind discounts	15% decrease or 5% increase	**-19**
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	**+74**
		Wind discounts	2% decrease or 2% increase	**-92**

(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, 2024		
Description	**Valuation technique**	**Unobservable input**	**Reasonably possible change**	**Sensitivity[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 would arise from the use of the reasonably possible changes of all unobservable inputs.

(2) Renewable energy credits.

a. 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.

b. 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.

c. 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.

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 asset fair value of $5 million as at March 31, 2025 (Dec. 31, 2024 – $4 million net liability) are classified as Level II fair value measurements.

IV. Other Financial Assets and Liabilities

	Fair value[1]			Total carrying value[1]
	Level II	Level III	Total	
Exchangeable securities — March 31, 2025	**746**	**—**	**746**	**750**
Long-term debt — March 31, 2025	**3,515**	**—**	**3,515**	**3,725**
Long-term financial assets — March 31, 2025[2]	**—**	**105**	**105**	**105**
Loan receivable — March 31, 2025[3]	**28**	**—**	**28**	**28**
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[3]	25	—	25	25

(1) Includes current portion.

(2) Refer to Note 10 for further details.

(3) Included within Other assets.

During the first quarter of 2025, the Company made available a US$75 million term loan, which is convertible to equity at any time, and a US$100 million revolving facility (collectively, 'the Nova facilities') to Nova. Refer to Note 10 for more details. The Nova facilities are classified as financial assets measured at FVTPL. The fair value of the Nova facilities are categorized as Level 3 in the fair value hierarchy as their fair value is determined using multiple inputs such as volatility and share price for which observable market data is not available. The Nova facilities are valued at the exchange amount, which represents the amounts drawn. There have been no material movements in the fair value to the end of the reporting period.

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 long-term financial assets and 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 11 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 condensed 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. Effective January 1, 2025, the difference is calibrated at initial recognition and no inception gains or losses are recognized.

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:

3 months ended March 31	2025	2024
Unamortized net gain at beginning of period	**11**	3
New inception gains	**—**	4
Change in foreign exchange rates	**—**	(1)
Amortization recorded in net earnings during the period	**(5)**	8
Unamortized net gain at end of period	**6**	14

12. 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. Refer to Note 15 of the 2024 audited annual consolidated financial statements for further details of the Company's risk management activities.

B. Net Risk Management Assets and Liabilities

Aggregate net risk management assets (liabilities) are as follows:

As at March 31, 2025

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	**34**	**29**	**63**
Long-term	**—**	**(232)**	**(232)**
Net commodity risk management assets (liabilities)	**34**	**(203)**	**(169)**
Other			
Current	**—**	**(1)**	**(1)**
Long-term	**—**	**6**	**6**
Net other risk management liabilities	**—**	**5**	**5**
Total net risk management assets (liabilities)	**34**	**(198)**	**(164)**

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)

C. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

i. Commodity Price Risk – 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.

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. Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at March 31, 2025, associated with the Company's proprietary trading activities was $1 million (Dec. 31, 2024 — $3 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 March 31, 2025, associated with the Company's commodity derivative instruments used in generation hedging activities was $10 million (Dec. 31, 2024 — $8 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 March 31, 2025, associated with these transactions was $10 million (Dec. 31, 2024 — $13 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 11(B)(II).

II. Credit Risk

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 March 31, 2025:

	Investment grade (per cent)	Non-investment grade (per cent)	Total (per cent)	Total amount
Trade and other receivables(1)	86	14	100	**873**
Long-term finance lease receivable	100	—	100	**297**
Risk management assets(1)	52	48	100	**407**
Long-term financial assets(2)	—	100	100	**105**
Loans receivable(3)	—	100	100	**28**
Total				**1,710**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.

(2) Included within long-term financial assets with counterparties that have no external credit rating. Refer to Note 10 for further details.

(3) Includes $28 million loans receivable included within other assets with counterparties that have no external credit rating.

The Company did not have material expected credit losses as at March 31, 2025. The Company's maximum exposure to credit risk at March 31, 2025, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of receivables, risk management assets, and long-term financial assets as per the condensed consolidated statements of financial position. Letters of credit, cash, and first priority liens on assets 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 March 31, 2025, was $69 million (Dec. 31, 2024 — $77 million).

III. Liquidity Risk

The Company has sufficient existing liquidity available to meet its upcoming debt maturities. The next major debt repayment is scheduled for the fourth quarter of 2029. Our highly diversified asset portfolio, by both fuel type and operating region, and our long-term contracted asset base provide stability in our cash flows.

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.

A maturity analysis of the Company's financial liabilities is as follows:

	2025	2026	2027	2028	2029	2030 and thereafter	Total
Accounts payable, accrued liabilities and other current liabilities	751	—	—	—	—	—	751
Credit facilities and long-term debt[1]	139	169	330	362	821	1,940	3,761
Exchangeable securities[2]	—	—	—	—	—	750	750
Commodity risk management (assets) liabilities[3]	(70)	2	4	5	1	227	169
Other risk management assets	(2)	—	—	—	(1)	(2)	(5)
Lease liabilities	4	5	5	5	5	128	152
Interest on credit facilities, long-term debt and lease liabilities[4]	168	212	203	180	161	711	1,635
Interest on exchangeable securities[2][4]	40	53	53	52	12	—	210
Dividends payable	37	—	—	—	—	—	37
Total	**1,067**	**441**	**595**	**604**	**999**	**3,754**	**7,460**

(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.

(3) Negative amount represents a receivable position or cash inflow.

(4) Not recognized as a financial liability on the condensed consolidated statements of financial position and excludes the impact of interest rate swaps.

D.Collateral

I. Financial Assets Provided as Collateral

At March 31, 2025, the Company provided $148 million (Dec. 31, 2024 — $124 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 condensed consolidated statements of financial position. At March 31, 2025, the Company provided $21 million (Dec. 31, 2024 — $21 million) in surety bonds as security for commodity trading activities.

II. Financial Assets Held as Collateral

At March 31, 2025, the Company held $21 million (Dec. 31, 2024 — $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 condensed 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 March 31, 2025, the Company had posted collateral of $397 million (Dec. 31, 2024 — $424 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 $101 million (Dec. 31, 2024 — $128 million) of collateral to its counterparties.

13. Property, Plant and Equipment

During the three months ended March 31, 2025, the Company had additions of $32 million, mainly related to major maintenance for various projects in the Gas, Wind and Solar and Hydro segments.

During the three months ended March 31, 2025, the Company did not capitalize any interest to property, plant, and equipment (PP&E). At March 31, 2024, the Company capitalized $14 million interest to PP&E at a weighted average rate of 6.5 per cent.

14. Credit Facilities, Long-Term Debt and Lease Liabilities

A. Amounts Outstanding

The Company's credit facilities are summarized in the table below:

As at March 31, 2025		Utilized			
Credit facilities	**Facility size**	**Outstanding letters of credit[(1)]**	**Cash drawings**	**Available capacity**	**Maturity date**
Committed					
Syndicated credit facility	1,950	372	199	1,379	Q2 2028
Bilateral credit facilities	240	167	—	73	Q2 2026
Heartland credit facilities	276	26	224	26	Q4 2027
Heartland EDC letter of credit facility	30	14	—	16	Q4 2025
Total committed	**2,496**	**579**	**423**	**1,494**	
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 March 31, 2025, TransAlta provided cash collateral of $148 million.

Credit facilities are the primary source of short-term liquidity after internally generated cash flow. The Company is in compliance with the terms of its 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 which are fully backstopped, thereby reducing the available capacity on the committed credit facilities. In addition to the net $1.3 billion of committed capacity available under the credit facilities, the Company had $238 million of available cash and cash equivalents as at March 31, 2025.

TransAlta's debt has terms and conditions, including financial covenants, that are considered ordinary and customary. As at March 31, 2025, the Company was in compliance with all of its debt covenants.

B.Senior Notes Offering

On March 24, 2025, the Company issued $450 million of senior notes with a fixed annual coupon of 5.625 per cent, maturing on March 24, 2032. The notes are unsecured and rank equally in right of payment with all existing and future senior indebtedness and senior in right of payment to all future subordinated indebtedness. Interest payments on the notes are made semi-annually, on March 24 and Sept. 24, with the first payment commencing Sept. 24, 2025.

C. Term Loan Facility Early Repayment

On March 25, 2025, the Company repaid its $400 million variable rate term loan facility in advance of the scheduled maturity date of Sept. 7, 2025, with the proceeds received from the $450 million senior notes offering.

D. 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 $1.7 billion as at March 31, 2025 (Dec. 31, 2024 — $1.8 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 first quarter of 2025. The funds in the entities will remain there until the next debt service coverage ratio can be performed in the second quarter of 2025. At March 31, 2025, $85 million (Dec. 31, 2024 — $117 million) of cash was subject to these financial restrictions.

At March 31, 2025, $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.

E. Restricted Cash

As at March 31, 2025, the Company had nil (Dec. 31, 2024 — $17 million) of restricted cash related to the TransAlta OCP bonds, which is required to be held in a debt service reserve account in the third and fourth quarters of the year to fund scheduled future debt repayments. The Company also had $51 million (Dec. 31, 2024 — $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.

15. Common Shares

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value.

	2025		2024	
3 months ended March 31	**Common shares (millions)**	**Amount**	**Common shares (millions)**	**Amount**
Issued and outstanding, beginning of period	**297.5**	**3,179**	306.9	3,285
Reversal of provision for repurchase of common shares under ASPP	**—**	**—**	1.7	19
Purchased and cancelled under the NCIB[1]	**(0.3)**	**(3)**	(3.5)	(37)
Share-based payment plans	**0.9**	**7**	0.7	10
Stock options exercised	**—**	**—**	0.7	3
Issued and outstanding, end of year, prior to ASPP	**298.1**	**3,183**	306.5	3,280
Provision for repurchase of common shares under ASPP	**(1.5)**	**(20)**	(2.5)	(22)
Issued and outstanding, end of period	**296.6**	**3,163**	304.0	3,258

(1) 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).

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:

3 months ended March 31	2025	2024
Total shares purchased[1]	**294,200**	3,460,300
Average purchase price per share	**13.59**	9.36
Total cost ($ millions)	**4**	32
Book value of shares cancelled	**3**	37
Amount recorded in deficit	**(1)**	5

(1) The three months ended March 31, 2025 include 74,600 shares (March 31, 2024 — 300,000 shares) that were repurchased but were not cancelled due to timing differences between the transaction date and settlement date. As a result, $1 million (2024 — $2 million) was paid subsequent to period end.

On March 25, 2025, the Company entered into an Automatic Securities Purchase Plan (ASPP) which permits an independent broker to repurchase shares under the NCIB during the first quarter blackout period through to the end of the ASPP. The Company has recognized a provision of $20 million for the repurchase of common share under the ASPP within accounts payable and accrued liabilities as at March 31, 2025, as an estimate of the maximum aggregate purchase amount that could be achieved during the blackout period.

C. Dividends

On Feb. 20, 2025, the Company declared a quarterly dividend of $0.065 per common share, payable on July 1, 2025. There have been no other transactions involving common shares between the reporting date and the date of completion of these condensed consolidated financial statements.

16. Preferred Shares

A. Issued and Outstanding

All preferred shares issued and outstanding are non-voting cumulative redeemable fixed or floating rate first preferred shares.

	March 31, 2025		Dec. 31, 2024	
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.

On April 23, 2025, the Company declared a quarterly dividend of $0.17981 per share on the Series A preferred shares, $0.30342 per share on the Series B preferred shares, $0.36588 per share on the Series C preferred shares, $0.37011 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 June 30, 2025.

17. Commitments and Contingencies

While the Company has not incurred any additional material contractual commitments in the three months ended March 31, 2025, either directly or through its interests in joint operations and joint ventures, there were reductions to the expected future payments under the Company's long-term service agreements in the three months ended March 31, 2025.

Total revised approximate future payments under the long-term service agreements are as follows:

	2025	2026	2027	2028	2029	2030 and thereafter	Total
Long-term service agreements	50	44	42	26	14	128	304

Refer to the commitments disclosed in Note 37 of the 2024 audited annual consolidated financial statements.

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 160 TJ per day on average and up to approximately 450 TJ per day during peak periods, while remarketing the excess capacity.

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 and turbines at various wind facilities.

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. The Company 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. Refer to Note 37 of the 2024 audited annual consolidated financial statements for the current material outstanding contingencies. There were no material changes to the contingencies in the three months ended March 31, 2025.

18. Segment Disclosures

A. Description of Reportable Segments

The Company has six reportable segments as described in Note 1 of the Company's 2024 audited annual consolidated financial statements. The Gas reportable segment includes Heartland, which was acquired on Dec. 4, 2024. Refer to Note 4 of the 2024 audited annual consolidated financial statements for further details of the Heartland Generation business acquisition and preliminary purchase price allocation. There were no adjustments made to the preliminary purchase price allocation as at March 31, 2025.

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 tables below show the reconciliation of the total segmented results and adjusted EBITDA to the statement of earnings reported under IFRS.

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.

B. Reported Adjusted Segment Earnings and Segment Assets

I. Reconciliation of Adjusted EBITDA to Earnings before Income Tax

3 months ended March 31, 2025	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	86	107	390	154	27	1	765	(7)	—	758
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(21)	36	(32)	(1)	1	—	(17)	—	17	—
Decrease in finance lease receivable	—	1	7	—	—	—	8	—	(8)	—
Finance lease income	—	1	5	—	—	—	6	—	(6)	—
Revenues from Planned Divestitures	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted revenue	65	145	366	153	28	1	758	(7)	7	758
Fuel and purchased power	4	10	163	98	—	2	277	—	—	277
Reclassifications and adjustments:										
Fuel and purchased power related to Planned Divestitures	—	—	(2)	—	—	—	(2)	—	2	—
Adjusted fuel and purchased power	4	10	161	98	—	2	275	—	2	277
Carbon compliance	—	1	49	—	—	(1)	49	—	—	49
Adjusted gross margin	61	134	156	55	28	—	434	(7)	5	432
OM&A	13	29	59	17	7	49	174	(1)	—	173
Reclassifications and adjustments:										
OM&A related to the Planned Divestitures	—	—	(2)	—	—	—	(2)	—	2	—
ERP integration costs	—	—	—	—	—	(4)	(4)	—	4	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(4)	(4)	—	4	—
Adjusted OM&A	13	29	57	17	7	41	164	(1)	10	173
Taxes, other than income taxes	1	5	5	1	—	—	12	—	—	12
Net other operating income	—	(4)	(10)	—	—	—	(14)	—	—	(14)
Reclassifications and adjustments:										
Insurance recovery	—	2	—	—	—	—	2	—	(2)	—
Adjusted net other operating income	—	(2)	(10)	—	—	—	(12)	—	(2)	(14)
Adjusted EBITDA[2]	47	102	104	37	21	(41)	270			
Depreciation and amortization										(146)
Equity income										2
Interest income										5
Interest expense										(93)
Foreign exchange loss										(4)
Finance lease income										6
Fair value change in contingent consideration										34
Asset impairment charges										(15)
Loss on sale of assets and other										(1)
Earnings before income taxes										49

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA is not defined, has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions.

3 months ended March 31, 2024	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	112	139	433	217	52	—	953	(6)	—	947
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(5)	(21)	(91)	(6)	(3)	—	(126)	—	126	—
Decrease in finance lease receivable	—	1	4	—	—	—	5	—	(5)	—
Finance lease income	—	1	1	—	—	—	2	—	(2)	—
Unrealized foreign exchange gain on commodity	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted revenues	107	120	346	211	49	—	833	(6)	120	947
Fuel and purchased power	6	9	142	166	—	—	323	—	—	323
Carbon compliance	—	—	40	—	—	—	40	—	—	40
Adjusted gross margin	101	111	164	45	49	—	470	(6)	120	584
OM&A	13	20	46	18	10	28	135	(1)	—	134
Reclassifications and adjustments:										
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(3)	(3)	—	3	—
Adjusted OM&A	13	20	46	18	10	25	132	(1)	3	134
Taxes, other than income taxes	1	4	3	—	—	—	8	—	—	8
Net other operating income	—	(2)	(10)	—	—	—	(12)	—	—	(12)
Adjusted EBITDA[2][3]	87	89	125	27	39	(25)	342			
Depreciation and amortization										(124)
Equity income										1
Interest income										7
Interest expense										(69)
Foreign exchange loss[4]										(5)
Finance lease income										2
Asset impairment charges										(1)
Gain on sale of assets[4]										2
Earnings before income taxes										267

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA is a non-IFRS measures, is not defined, have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers.

(3) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. During the second quarter of 2024, our Adjusted EBITDA composition was amended to exclude the impact of acquisition-related transaction and restructuring costs. Therefore, the Company has applied this composition to all previously reported periods.

(4) Foreign exchange loss and other of $3 million reported in the first quarter of 2024 was broken down to conform to the current period presentation.

19. Related-Party Transactions

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.

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 condensed 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. Refer to Note 26 and 36 of the 2024 audited annual consolidated financial statements.

Transactions with Brookfield include the following:

	3 months ended March 31	
Year ended Dec. 31	**2025**	**2024**
Power sales	**28**	21
Purchased power	**—**	3

Glossary of Key Terms

Alberta Electric System Operator (AESO)

The independent system operator and regulatory authority for the Alberta Interconnected Electric System. authority for the Alberta Interconnected Electric System.

Alberta Hydro Assets

The Company's hydroelectric assets, owned through a wholly owned subsidiary, TransAlta Renewables Inc. These assets are located in Alberta consisting of the Barrier, Bearspaw, Cascade, Ghost, Horseshoe, Interlakes, Kananaskis, Pocaterra, Rundle, Spray, Three Sisters, Bighorn and Brazeau 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 (Alberta), 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 Securities 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.

Capacity

The rated continuous load-carrying ability, expressed in megawatts, of generation equipment.

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 fulfill contractual obligations, when economical.

Economic Dispatch

Power is not produced during periods of low market price, but is purchased in the market to fulfil the contract.

Exchangeable Debentures

On May 1, 2019, Brookfield Renewable Partners or its affiliates (collectively, 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

The Exchangeable Debentures and the Exchangeable Preferred Shares 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).

Free Cash Flow (FCF)

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. FCF is calculated as 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)

Represents 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 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 (kWh).

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.

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).

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, Ontario which include the Taylor, Belly River, Waterton, St. Mary, Upper Mamquam, Pingston, Bone Creek, Akolkolex, Ragged Chute, Misema, Galetta, and Moose Rapids facilities.

Planned Divestitures

To meet the requirements of the federal Competition Bureau related to the Heartland Generation acquisition, 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 acquisition of Heartland Generation.

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 on line.

Power Purchase Agreement (PPA)

A long-term commercial agreement 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.

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 former $400 million term facility with our banking syndicate, maturing on Sept. 7, 2025, with floating interest rates that vary depending on the option selected (e.g., Canadian prime and bankers' acceptances).

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.

Unplanned outage

The shutdown of a generating unit due to an unanticipated breakdown.

Value at Risk (VaR)

A measure used to manage exposure to market risk from commodity risk management activities.