TRANSALTA CORPORATION Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A) contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. Refer to the Forward-Looking Statements section of this MD&A for additional information.

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This MD&A should be read in conjunction with our unaudited interim condensed consolidated financial statements as at and for the three and six months ended June 30, 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 June 30, 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 July 31, 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;
- The optimization and diversification of our generating assets;
- The increasingly contracted nature of our fleet;
- Expectations about strategies for growth and expansion, including opportunities for Centralia redevelopment, and data centre opportunities;
- Expectations regarding ongoing and future transactions, including our divestiture of Poplar Hill;
- 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 or foreign exchange rates;
- No significant changes to the demand for, and growth of, renewables and thermal 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;
- No significant event occurring outside the ordinary course of business; and
- Realization of expected impacts from ongoing and future transactions.

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;
- Failure to complete divestitures on the terms and conditions specified or at all;
- 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, 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 and hydro generation capacity in Alberta may be 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 section 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 June 30, 2025:

	Hydro		Wind & Solar		Gas		Energy Transition		Total	
As at June 30, 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 June 30, 2025:

As at June 30, 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 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 June 30, 2025:

As at June 30, 2025	Hydro	Wind & Solar	Gas(1)	Energy Transition	Total
Alberta	—	7	2	—	3
Canada, excluding Alberta	15	9	6	—	8
U.S.	—	12	1	—	7
Western Australia	—	14	13	—	13
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 and six months ended June 30, 2025, the Company delivered strong operational and financial performance. 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 Key Performance Indicators exclude the results of the Planned Divestitures.

	3 months ended June 30		6 months ended June 30	
(in millions of Canadian dollars except where noted)	2025	2024	2025	2024
Operational information				
Availability (%)	**91.6**	90.8	**93.3**	91.5
Production (GWh)	**4,813**	4,781	**11,645**	10,959
Select financial information				
Revenues	**433**	582	**1,191**	1,529
Adjusted EBITDA[(1)]	**349**	316	**619**	658
Adjusted earnings before income taxes[(1)]	**122**	112	**150**	256
(Loss) earnings before income taxes	**(95)**	94	**(46)**	361
Adjusted net earnings attributable to common shareholders[(1)]	**54**	70	**84**	197
Net (loss) earnings attributable to common shareholders	**(112)**	56	**(66)**	278
Cash flows				
Cash flow from operating activities	**157**	108	**164**	352
Funds from operations[(1)]	**252**	236	**431**	490
Free cash flow[(1)]	**177**	177	**316**	398
Per share				
Weighted average number of common shares outstanding	**297**	303	**297**	306
Adjusted net earnings attributable to common shareholders per share[(1)(2)]	**0.18**	0.23	**0.28**	0.64
Net (loss) earnings per share attributable to common shareholders, basic and diluted	**(0.38)**	0.18	**(0.22)**	0.91
Dividends declared per common share	**—**	0.06	**0.07**	0.06
Cash flow from operating activities per share	**0.53**	0.36	**0.55**	1.15
Funds from operations per share[(1)(2)]	**0.85**	0.78	**1.45**	1.60
Free cash flow per share[(1)(2)]	**0.60**	0.58	**1.06**	1.30

(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. We believe that 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	June 30, 2025	Dec. 31, 2024
Liquidity and capital resources		
Available liquidity[(1)]	**1,497**	1,616
Adjusted net debt to adjusted EBITDA (times)[(2)(3)]	**3.8**	3.6
Total consolidated net debt[(2)(4)]	**3,892**	3,798
Assets and liabilities		
Total assets	**8,939**	9,499
Total long-term liabilities[(5)]	**5,448**	5,087
Total liabilities[(6)]	**7,276**	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 $3,761 million (Dec. 31, 2024 — $3,808 million) divided by loss before income taxes for the last four quarters of $88 million (Dec. 31, 2024 — $319 million) and is equal to (43) 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 $3,761 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 June 30		6 months ended June 30	
	2025	**2024**	**2025**	**2024**
Hydro	**97.0**	90.5	**95.3**	91.2
Wind and Solar	**94.7**	94.3	**94.3**	93.9
Gas	**90.2**	95.3	**92.9**	94.9
Energy Transition	**81.3**	59.0	**89.1**	69.0
Availability (%)	**91.6**	90.8	**93.3**	91.5

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 shift or change to accelerate the return to service of the unit.

Availability for the three months ended June 30, 2025, was 91.6 per cent compared to 90.8 per cent in the same period in 2024. Higher availability compared to the prior period was primarily due to:

- Lower planned and unplanned outages at the Centralia facility in the Energy Transition segment; and
- Lower planned and unplanned maintenance outages in the Hydro segment; partially offset by
- Higher unplanned outages in the Gas segment.

Availability for the six months ended June 30, 2025 was 93.3 per cent compared to 91.5 per cent in the same period in 2024. Higher availability compared to the same period in 2024 was primarily due to:

- Lower planned and unplanned outages at the Centralia facility in the Energy Transition segment;
- Lower planned and unplanned maintenance outages in the Hydro segment; and
- The full two quarter impact from the addition of the White Rock and Horizon Hill wind facilities, which operated at higher availability; partially offset by
- Higher unplanned outages in the Gas segment.

Production and Long-Term Average Generation

The following table provides the production and long-term average generation (LTA generation) on a consolidated basis for each of our segments:

	2025			2024		
3 months ended June 30	**Actual production (GWh)**	**LTA generation (GWh)**	**Production as a % of LTA**	**Actual production (GWh)**	**LTA generation (GWh)**	**Production as a % of LTA**
Hydro	**572**	**593**	**96%**	426	593	72%
Wind and Solar(1)	**1,513**	**1,754**	**86%**	1,499	1,618	93%
Gas	**2,486**			2,854		
Energy Transition	**242**			2		
Total	**4,813**			4,781		

(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.

	2025			2024		
6 months ended June 30	**Actual production (GWh)**	**LTA generation (GWh)**	**Production as a % of LTA**	**Actual production (GWh)**	**LTA generation (GWh)**	**Production as a % of LTA**
Hydro	**955**	**995**	**96%**	777	995	78%
Wind and Solar(1)	**3,418**	**3,810**	**90%**	2,997	3,262	92%
Gas	**5,990**			6,382		
Energy Transition	**1,282**			803		
Total	**11,645**			10,959		

(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 June 30, 2025, increased by 32 GWh, or one per cent compared to the same period in 2024, primarily due to:

- Production from the Heartland gas facilities acquired in December 2024;
- Improved availability at Centralia due to lower planned and unplanned outages, as well as stronger market conditions compared to the same periods in 2024; and
- Higher production in the Hydro segment due to lower planned and unplanned maintenance outages and optimization of water supply; partially offset by
- Higher dispatch optimization in Alberta in the Gas segment due to lower market prices; and
- Lower production in Australia due to lower customer demand.

Total production for the six months ended June 30, 2025, increased by 686 GWh, or six per cent compared to the same period in 2024, primarily due to:

- Production from the Heartland gas facilities acquired in December 2024;
- Improved availability at Centralia due to lower planned and unplanned outages, as well as stronger market conditions compared to the same periods in 2024;
- The full two quarters of production from 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;
- Higher production in the Hydro segment due to higher water reserves, lower planned and unplanned maintenance outages and optimization of water supply; and
- Higher wind resource across Eastern Canada; partially offset by
- Higher dispatch optimization in Alberta in the Gas segment due to lower market prices; and
- Lower production in Australia due to lower customer demand.

Market Pricing

	3 months ended June 30		6 months ended June 30	
	2025	**2024**	**2025**	**2024**
Alberta spot power price ($/MWh)	**40**	45	**40**	72
Mid-Columbia spot power price (US$/MWh)	**34**	29	**42**	67
Ontario spot power price[1] ($/MWh)	**36**	28	**50**	31
Natural gas price (AECO) per GJ ($)	**1.64**	1.14	**1.83**	1.54

(1) Ontario spot power prices through April 2025 are based on the hourly Ontario energy price (HOEP). Starting May 2025 prices are based on the settled day ahead hourly Ontario zonal energy prices.

For the three and six months ended June 30, 2025, spot power prices in Alberta were 11 per cent and 44 per cent lower, respectively, compared to the same periods in 2024, driven by a generally mild winter and increased supply from new renewable and gas-fired facilities.

For the three months ended June 30, 2025, spot power prices in the Pacific Northwest were 17 per cent higher compared to the same period in 2024, due to lower water year and higher prices in California.

For the six months ended June 30, 2025, spot power prices in the Pacific Northwest were 37 per cent lower compared to the same period in 2024, due to a milder winter.

Ontario spot power prices were higher on average compared to the same periods in 2024, due to nuclear refurbishments occurring in 2025 and higher natural gas prices.

For the three and six months ended June 30, 2025, AECO natural gas prices were 44 and 19 per cent higher, respectively, compared to the same periods in 2024, mainly due to lower storage levels in Alberta and throughout North America, as well as stronger demand.

Financial Performance Review of Consolidated Information

	3 months ended June 30		6 months ended June 30	
	2025	**2024**	**2025**	**2024**
Revenues	**433**	582	**1,191**	1,529
Fuel and purchased power	**(173)**	(154)	**(450)**	(477)
Carbon compliance recovery (costs)	**74**	8	**25**	(32)
Operations, maintenance and administration	**(173)**	(144)	**(346)**	(278)
Depreciation and amortization	**(150)**	(131)	**(296)**	(255)
Asset impairment charges	**(13)**	(5)	**(28)**	(6)
Fair value change in contingent consideration payable	**—**	—	**34**	—
Interest expense	**(88)**	(80)	**(181)**	(149)
Foreign exchange loss	**(17)**	(1)	**(21)**	(6)
(Loss) Earnings before income taxes	**(95)**	94	**(46)**	361
Income tax expense	**(11)**	(28)	**(18)**	(57)
Net (loss) earnings attributable to common shareholders	**(112)**	56	**(66)**	278
Net (loss) earnings attributable to non-controlling interests	**(7)**	(3)	**(11)**	13

Three months ended June 30, 2025 Variance Analysis (2025 versus 2024)

Revenues for the three months ended June 30, 2025 decreased by $149 million, or 26 per cent, compared to the same period in 2024, primarily due to:

- Lower revenue from derivatives and other trading activities in the Gas segment driven by higher unrealized mark-to-market losses primarily related to unfavourable hedging positions in the current period;
- 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 Garden Plain facilities and changes to wind discount assumptions; and
- Higher unrealized mark-to-market losses recorded in the Energy Transition and Hydro segments primarily related to the unfavourable changes in forward prices; partially offset by
- The full quarter impact from the addition of the Heartland facilities in the fourth quarter of 2024.

Fuel and purchased power costs for the three months ended June 30, 2025 increased by $19 million, or 12 per cent, compared to the same period in 2024, primarily due to:

- Full quarter impact from the addition of the Heartland facilities in the fourth quarter of 2024;
- Higher gas prices; and
- Higher production in the Energy Transition segment; partially offset by
- Lower production in Alberta.

Carbon compliance recovery for the three months ended June 30, 2025 increased by $66 million compared to the same period in 2024, primarily due to:

- Utilization of higher quantity of internally generated emission credits in the current period compared to the same period of prior year to settle a portion of our 2024 GHG obligation and a portion of the GHG obligation assumed in the Heartland acquisition; and
- Lower fuel consumption in the Gas segment compared to the same period in 2024; partially offset by
- An increase in the carbon price from $80 per tonne in 2024 to $95 per tonne in 2025.

OM&A expenses for the three months ended June 30, 2025 increased by $29 million, or 20 per cent, compared to the same period in 2024, primarily due to:

- Higher spending to support strategic and growth initiatives;
- Full quarter impact from the addition of the Heartland facilities in the fourth quarter of 2024 and associated corporate costs; and
- Higher spending related to the planning and design of an upgrade to our enterprise resource planning (ERP) system.

Depreciation and amortization for the three months ended June 30, 2025 increased by $19 million, or 15 per cent, compared to the same period in 2024, primarily due to:

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

Asset impairment charges for the the three months ended June 30, 2025 increased by $8 million, or 160 per cent, compared to the same period in 2024, primarily due to an increase in decommissioning and restoration provisions on retired assets driven by a decrease in discount rates.

Interest expense for the three months ended June 30, 2025 increased by $8 million, or 10 per cent, compared to the same period in 2024, primarily due to:

- Higher credit facility fees in the current period; and
- Lower capitalized interest resulting from lower construction activity during 2025 compared to the same period in 2024.

Foreign exchange loss for the three months ended June 30, 2025 increased by $16 million compared to the same period in 2024, primarily due to:

- Higher unrealized foreign exchange losses due to unfavourable changes in foreign currency rates; partially offset by
- Higher realized foreign exchange gains due to hedges settled during the period at favourable foreign currency rates.

Loss before income taxes for the three months ended June 30, 2025 increased by $189 million from earnings before income taxes in 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 for the three months ended June 30, 2025 decreased by $17 million, or 61 per cent, compared to the same period in 2024, due to the increase in loss before income taxes; partially offset by higher valuation allowance on US operations.

Net loss attributable to non-controlling interests for the three months ended June 30, 2025 decreased by $4 million, or 133 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.

Six months ended June 30, 2025 Variance Analysis (2025 versus 2024)

Revenues for the six months ended June 30, 2025 decreased by $338 million, or 22 per cent, compared to the same period in 2024, primarily due to:

- Lower power prices in Alberta;
- Higher dispatch optimization in the Gas segment driven by lower power prices in Alberta;
- Lower revenue from derivatives and other trading activities in the Gas segment driven by higher unrealized mark-to-market losses primarily related to unfavourable hedging positions in the current period; and
- 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 Garden Plain and Oklahoma facilities, primarily due to higher forecasted power prices; partially offset by
- The full two quarter impact from the addition of the Heartland facilities in the fourth quarter of 2024.

Fuel and purchased power costs for the six months ended June 30, 2025 decreased by $27 million, or six per cent, compared to the same period in 2024 due to:

- Lower purchased power costs driven by lower Mid-Columbia prices in the Energy Transition segment;
- Lower gas costs due to lower gas production in Alberta partially offset by
- Full two quarter impact from the addition of the Heartland facilities in the fourth quarter of 2024; and
- Higher production in the Energy Transition segment.

Carbon compliance recovery for the six months ended June 30, 2025 increased by $57 million from carbon compliance costs in the same period in 2024, primarily due:

- Utilization of higher quantity of internally generated emission credits in the current period compared to the same period of prior year to settle a portion of our 2024 GHG obligation and a portion of the GHG obligation assumed in the Heartland acquisition; and
- Lower fuel consumption in the Gas segment compared to the same period in 2024; partially offset by
- An increase in the carbon price from $80 per tonne in 2024 to $95 per tonne in 2025.

OM&A expenses for the six months ended June 30, 2025 increased by $68 million, or 24 per cent, compared to the same period in 2024, primarily due to:

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

Depreciation and amortization for the six months ended June 30, 2025 increased by $41 million, or 16 per cent, compared to the same period in 2024, primarily due to:

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

Asset impairment charges for the six months ended June 30, 2025 increased by $22 million, or 367 per cent, 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; 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 for the six months ended June 30, 2025 totalling $34 million was driven by updated expectations of the fair value less costs to sell on the Planned Divestitures.

Interest expense for the six months ended June 30, 2025 increased by $32 million, or 21 per cent, compared to the same period in 2024, primarily due to:

- Lower capitalized interest resulting from lower construction activity during 2025 compared to the same period in 2024; and
- Higher credit facility fees in the current period.

Foreign exchange loss for the six months ended June 30, 2025 increased by $15 million or 250 per cent due to:

- Higher unrealized foreign exchange losses due to unfavourable changes in foreign currency rates; partially offset by
- Higher realized foreign exchange gains due to hedges settled during the period at favourable foreign currency rates.

Loss before income taxes for the six months ended June 30, 2025 increased by $407 million from earnings before income taxes in 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 for the six months ended June 30, 2025 decreased by $39 million, or 68 per cent, compared to the same period in 2024, due to the increase in loss before income taxes; partially offset by higher valuation allowance on US operations.

Net loss attributable to non-controlling interests for the six months ended June 30, 2025 decreased by $24 million from net earnings attributable to non-controlling interests in the same period in 2024, primarily due to lower net earnings for TA Cogen resulting from lower merchant pricing in the Alberta market.

Adjusted EBITDA

For the three and six months ended June 30, 2025, the Company's Adjusted EBITDA was $349 million and $619 million, respectively, as compared to $316 million and $658 million, respectively, in 2024, an increase of $33 million and a decrease of $39 million, respectively, or 10 and six per cent, respectively. The major factors impacting Adjusted EBITDA are summarized in the following table:

	3 months ended June 30
Adjusted EBITDA for the three months ended June 30, 2024[1]	316
Hydro: Higher primarily due to higher environmental and tax attributes revenue due to increased intercompany sales of emission credits to the Gas segment to fulfill our 2024 GHG obligation, higher merchant and ancillary services volumes due to higher availability and higher ancillary services prices, partially offset by lower spot power prices in the Alberta market.	43
Wind and Solar: Higher primarily due to higher environmental and tax attributes revenue due to increased sales of emission credits to third parties and intercompany sales to the Gas segment, partially offset by lower tax attributes revenue from Oklahoma due to lower wind resource and lower Alberta pool prices.	1
Gas: Lower primarily due to higher dispatch optimization due to lower market prices, lower pool and realized power prices in the Alberta market, an increase in the carbon price, and higher natural gas prices, partially offset by the positive contributions from the addition of Heartland facilities and the increased quantity of emission credits utilized to settle a portion of our 2024 GHG obligation and a portion of the GHG obligation assumed in the Heartland acquisition.	(14)
Energy Transition: Higher primarily due to higher market optimization capturing benefits of Mid-Columbia price volatility and higher availability due to lower planned outages.	17
Energy Marketing: Lower primarily due to comparatively subdued market volatility across North American natural gas and power markets and lower realized settled trades in the second quarter of 2025 compared to the same period in 2024.	(13)
Corporate: Lower primarily due to increased spending to support strategic and growth initiatives, and the addition of corporate costs related to Heartland.	(1)
Adjusted EBITDA[2] for the three months ended June 30, 2025	**349**

(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. 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 loss before income taxes of $95 million for the three months ended June 30, 2025 and earnings before income taxes of $94 million for the three months ended June 30, 2024, respectively. Refer to Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segments section of this MD&A.

	6 months ended June 30
Adjusted EBITDA for the six months ended June 30, 2024[1]	658
Hydro: Higher primarily due to higher merchant and ancillary services volumes, higher environmental and tax attributes revenue due to increased intercompany sales of emission credits to the Gas segment to fulfill our 2024 GHG obligation, higher volume of favourable hedging positions settled, which generated positive contributions over settled spot prices in the current period, partially offset by lower spot power and ancillary services prices in the Alberta market.	3
Wind and Solar: Higher primarily due to positive contribution from the addition of the Horizon Hill, White Rock West and East wind facilities due to full first and second quarter production in 2025, higher environmental tax attribute revenue due to increased sales of emission credits to third parties and intercompany sales to the Gas segment, higher production volumes in Eastern Canada due to higher wind resource and higher tax attributes revenue from the sales agreements to transfer production tax credits from the Oklahoma facilities to taxable U.S. counterparties due to full two quarters of operations, partially offset by lower Alberta pool prices.	14
Gas: Lower primarily due to higher dispatch optimization due to lower market prices, lower pool and realized power prices in the Alberta market, and an increase in the carbon price, higher natural gas prices, partially offset by the positive contributions from the addition of Heartland facilities, higher volume of favourable hedge positions settled and the increased quantity of emission credits utilized to settle a portion of our 2024 GHG obligation and a portion of the GHG obligation assumed in the Heartland acquisition.	(35)
Energy Transition: Higher 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 due to increased economic dispatch driven by lower Mid-Columbia prices.	27
Energy Marketing: Lower primarily due to comparatively subdued market volatility across North American natural gas and power markets and lower realized settled trades in the first and second quarters of 2025 compared to the same period in 2024.	(31)
Corporate: Lower primarily due to increased spending to support strategic and growth initiatives, and the addition of corporate costs related to Heartland.	(17)
Adjusted EBITDA[2] for the six months ended June 30, 2025	**619**

(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. 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 loss before income taxes of $46 million for the six months ended June 30, 2025 and earnings before income taxes of $361 million for the six months ended June 30, 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 June 30, 2025, the Company's FCF remained consistent with the same period in 2024. For the six months ended June 30, 2025, the Company's FCF was lower 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 on this non-IFRS measure.

The major factors impacting FCF are summarized in the following table:

	3 months ended June 30
FCF for the three months ended June 30, 2024	177
Higher sustaining capital expenditures due to higher major maintenance at our Canadian gas facilities due to timing of spend and the addition of maintenance for the gas facilities acquired from Heartland, partially offset by no major maintenance occurring in the Energy Transition segment in the current period.	(17)
Higher current income tax expense due to higher non-deductible expenses for tax in 2025 compared to the same period in 2024, partially offset by higher loss before income taxes in 2025 compared to earnings before income taxes in the same period in 2024.	(13)
Higher net interest expense[(1)] due to higher credit facility fees and lower capitalized interest resulting from lower construction activity in the second quarter of 2025 compared to the same period in 2024.	(9)
Higher Adjusted EBITDA[(2)] due to the items noted above.	33
Lower distributions paid to subsidiaries' non-controlling interests relating to lower TA Cogen net earnings resulting from lower merchant pricing in the Alberta market.	3
Other non-cash items[(3)]	7
Other[(4)]	(4)
FCF[(5)] for the three months ended June 30, 2025	**177**

(1) 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 total interest expense of $88 million for the three months ended June 30, 2025 (June 30, 2024 — $80 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 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.

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

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

(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 $157 million and $108 million for the three months ended June 30, 2025 and 2024, respectively. Refer to the Cash Flows section of this MD&A.

	6 months ended June 30
FCF for the six months ended June 30, 2024	398
Lower Adjusted EBITDA[(1)] due to the items noted above.	(39)
Higher sustaining capital expenditures due to higher major maintenance at our Canadian gas facilities due to timing of spend and the addition of maintenance for the gas facilities acquired from Heartland, partially offset by no major maintenance occurring in the Energy Transition segment in the current period. In addition, the first quarter of 2024 was impacted by the receipt of a lease incentive related to the Company's head office.	(40)
Higher net interest expense[(2)] due to higher credit facility fees and lower capitalized interest resulting from lower construction activity in the current period compared to the same period in 2024.	(33)
Lower distributions paid to subsidiaries' non-controlling interests relating to lower TA Cogen net earnings resulting from lower merchant pricing in the Alberta market.	22
Other non-cash items[(3)]	2
Other[(4)]	6
FCF[(5)] for the six months ended June 30, 2025	**316**

(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. 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 $181 million for the six months ended June 30, 2025 (June 30, 2024 — $149 million).

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

(4) Other consists of lower realized foreign exchange losses, higher decommissioning and restoration costs settled, and lower current income tax expense.

(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 $164 million and $352 million for the six months ended June 30, 2025 and 2024, respectively. Refer to the Cash Flows section of this MD&A.

Capital Expenditures

Sustaining capital and growth and development capital expenditures represent supplementary financial measures used to present our spending related to the safe and reliable operation of our existing facilities and the construction of projects, respectively. The sum of sustaining capital and growth and development capital expenditures, adjusted for non-cash items and transfers, is equal to the additions to property, plant and equipment and intangible assets, and development capital expenditures 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 June 30		6 months ended June 30	
	2025	**2024**	**2025**	**2024**
Hydro	**6**	10	**10**	13
Wind and Solar	**7**	4	**11**	7
Gas	**40**	11	**51**	14
Energy Transition	**—**	12	**—**	12
Corporate	**4**	3	**8**	(6)
Sustaining capital expenditures	**57**	40	**80**	40

Total sustaining capital expenditures during the three and six months ended June 30, 2025 were $17 and $40 million higher, respectively, compared with the same periods in 2024, primarily due to:

- Higher major maintenance for our Canadian gas facilities due to timing of spend and the addition of maintenance for the gas facilities acquired from Heartland; partially offset by
- No major maintenance occurring in the Energy Transition segment in the current period.

Total sustaining capital expenditures for the six months ended June 30, 2025 were further impacted by the receipt of a lease incentive related to the Company's head office during the first quarter of 2024, included in the Corporate segment.

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 June 30		6 months ended June 30	
	2025	**2024**	**2025**	**2024**
Hydro	**1**	3	**1**	6
Wind and Solar	**—**	—	**—**	48
Gas	**15**	12	**26**	16
Energy Transition	**2**	—	**2**	—
Growth and development expenditures	**18**	15	**29**	70

In the six months ended June 30, 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.

Significant and Subsequent Events

Credit Facility Extension

On July 16, 2025, the Company executed agreements to extend committed credit facilities totalling $2.1 billion with a syndicate of lenders. The revised agreements extend the maturity dates of the syndicated credit facility from June 30, 2028 to June 30, 2029 and the bilateral credit facilities from June 30, 2026 to June 30, 2027.

Recontracting of Ontario Wind Facilities

During the second quarter of 2025, the Company successfully recontracted its Melancthon 1, Melancthon 2 and Wolfe Island wind facilities through the Ontario Independent Electricity System Operator Five-Year Medium-Term 2 Energy Contract (MT2e). MT2e will replace current energy contracts for the three wind facilities when they expire, extending the contract dates until April 30, 2031, for Melancthon 1 and April 30, 2034, for Melancthon 2 and Wolfe Island.

Divestiture of Poplar Hill

During the second quarter of 2025, the Company signed an agreement for the divestiture of the 48 MW Poplar Hill asset, as required by the consent agreement with the federal Competition Bureau and pursuant to the terms of the acquisition of Heartland Generation. Energy Capital Partners will be entitled to receive the proceeds from the sale of Poplar Hill, net of certain adjustments, following completion of the divestiture.

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. As at June 30, 2025, US$73 million was drawn by Nova under the credit facilities. The outstanding principal under the term loan and the revolving facility bear interest at 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

On April 1, 2025, the Company mothballed the Sundance Unit 6 facility 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.

On July 29, 2025 TransAlta's Board approved the quarterly dividend payment of $0.065 per common share.

Normal Course Issuer Bid (NCIB)

On May 27, 2025, the Company announced that it had received approval from the Toronto Stock Exchange to repurchase up to a maximum of 14 million common shares during the 12-month period that commenced May 31, 2025 and will terminate on May 30, 2026.

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.

During the six months ended June 30, 2025, the Company purchased and cancelled a total of 1,932,800 common shares at an average price of $12.42 per common share, for a total cost of $24 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 and six months ended June 30:

	3 months ended June 30		6 months ended June 30	
	2025	**2024**	**2025**	**2024**
Hydro	**126**	83	**173**	170
Wind and Solar	**89**	88	**191**	177
Gas	**128**	142	**232**	267
Energy Transition	**19**	2	**56**	29
Energy Marketing	**26**	39	**47**	78
Corporate	**(39)**	(38)	**(80)**	(63)
Adjusted EBITDA[(1)(2)]	**349**	316	**619**	658
Adjusted earnings before income taxes[(1)]	**122**	112	**150**	256
(Loss) earnings before income taxes	**(95)**	94	**(46)**	361
Adjusted net earnings attributable to common shareholders[(1)]	**54**	70	**84**	197
Net (loss) earnings attributable to common shareholders	**(112)**	56	**(66)**	278

(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. 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.

Three months ended June 30, 2025 Variance Analysis (2025 versus 2024)

Adjusted earnings before income taxes for the three months ended June 30, 2025 increased by $10 million, or nine per cent, compared to the same period in 2024, primarily due to:

- The factors causing higher adjusted EBITDA described in the Adjusted EBITDA section of this MD&A; and
- Higher realized foreign exchange gains due to hedges settled during the period at favourable foreign currency rates; partially offset by
- Higher depreciation and amortization due to the addition of the Heartland gas facilities and full quarter impact from the addition of the White Rock and Horizon Hill wind facilities; and
- Higher interest expense due to higher credit facility fees and lower capitalized interest in the current period.

Adjusted net earnings attributable to common shareholders for the three months ended June 30, 2025 decreased by $16 million, or 23 per cent, compared to the same period in 2024, primarily due to:

- Higher calculated tax expense on adjustments and reclassifications compared to the same period in 2024; partially; offset by
- Lower income tax expense due to lower earnings compared to the same period in 2024; partially offset by higher valuation allowance on US operations.; and
- The factors causing higher adjusted earnings before income taxes described above.

Loss before income taxes for the three months ended June 30, 2025, increased by $189 million, or 201 per cent, compared to the same period in 2024, primarily due to:

- Higher unrealized mark-to-market losses recorded in the Gas segment driven by higher unrealized mark-to-market losses primarily related to unfavourable hedging positions in the current period;
- Higher unrealized mark-to-market losses recorded in the Wind and Solar segment primarily related to long-term wind energy sales related to the Garden Plain facilities and changes to wind discount assumptions;
- Higher unrealized mark-to-market losses recorded in the Energy Transition and Hydro segments primarily related to the unfavourable changes in forward prices;

- Higher unrealized foreign exchange losses due to unfavourable changes in foreign currency rates;
- Higher asset impairment charges due to an increase in decommissioning and restoration provisions on retired assets driven by a decrease in discount rates; partially offset by
- Higher adjusted earnings before income taxes noted above.

Net loss attributable to common shareholders for the three months ended June 30, 2025, increased by $168 million from net earnings attributable to common shareholders for the same period in 2024, primarily due to:

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

Six months ended June 30, 2025 Variance Analysis (2025 versus 2024)

Adjusted earnings before income taxes for the six months ended June 30, 2025 decreased by $106 million, or 41 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 in December 2024, White Rock West and East wind facilities commissioned in January and April 2024, respectively, and the Horizon Hill wind facility commissioned in May 2024; and
- Higher interest expense due to lower capitalized interest resulting from lower construction activity in the current period compared to the same period in 2024 and higher credit facility fees in the current period; partially offset by
- Higher realized foreign exchange gains compared to the same period.

Adjusted net earnings attributable to common shareholders for the six months ended June 30, 2025 decreased by $113 million, or 57 per cent, compared to the same period in 2024, primarily due to:

- The factors causing lower adjusted earnings before income taxes described above; and
- Higher calculated tax expense on adjustments and reclassifications compared to the same period in 2024; partially offset by
- Lower income tax expense due to lower earnings compared to the same period in 2024; partially offset by higher valuation allowance on US operations; and
- Net loss attributable to non-controlling interests in the current period compared to net earnings in the same period of 2024.

Loss before income taxes for six months ended June 30, 2025, increased by $407 million, or 113 per cent, from the same period in 2024, primarily due to:

- Higher unrealized mark-to-market losses recorded in the Gas segment driven by higher unrealized mark-to-market losses primarily related to unfavourable hedging positions in the current period;
- Higher unrealized mark-to-market losses recorded in the Wind and Solar segment primarily related to long-term wind energy sales related to the Garden Plain and Oklahoma facilities;
- The factors causing lower adjusted earnings before income taxes noted above;
- Higher unrealized mark-to-market losses recorded in the Energy Transition segment primarily related to the unfavourable changes in forward prices;
- Higher unrealized foreign exchange losses due to unfavorable changes in foreign currency rates;
- An impairment charge on Planned Divestiture assets classified as Assets Held for Sale;
- Higher asset impairment charges due to an increase in decommissioning and restoration provisions on retired assets driven by a decrease in discount rates; and
- Higher spending related to the planning and design of an upgrade to our ERP system; partially offset by
- An impairment reversal related to certain energy transition assets reclassified to assets held for sale.

Net loss attributable to common shareholders for the six months ended June 30, 2025 increased by $344 million, or 124 per cent, from net earnings attributable to common shareholders for the same period in 2024, primarily due to:

- The factors causing higher loss before income taxes above; partially offset by
- Lower income tax expense due to lower earnings compared to the same period in 2024, partially offset by higher valuation allowance on US operations in the current period; and
- Higher net loss attributable to non-controlling interests compared 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 June 30				6 months ended June 30			
	2025	2024	Change		2025	2024	Change	
Gross installed capacity (MW)	922	922	—	— %	922	922	—	— %
LTA generation (GWh)	593	593	—	— %	995	995	—	— %
Availability (%)	97.0	90.5	6.5	7 %	95.3	91.2	4.1	4 %
Production								
Contract production (GWh)	139	86	53	62 %	177	124	53	43 %
Merchant production (GWh)	433	340	93	27 %	778	653	125	19 %
Total energy production (GWh)	572	426	146	34 %	955	777	178	23 %
Ancillary service volumes (GWh)[1]	786	699	87	12 %	1,499	1,360	139	10 %
Alberta Hydro Assets revenues[2]	39	23	16	70 %	65	72	(7)	(10)%
Other Hydro Assets revenues and other Hydro revenues[3]	15	14	1	7 %	24	22	2	9 %
Alberta Hydro Assets ancillary services revenues[1]	33	24	9	38 %	53	60	(7)	(12)%
Environmental and tax attributes revenues	60	39	21	54 %	70	53	17	32 %
Adjusted revenues[4]	147	100	47	47 %	212	207	5	2 %
Fuel and purchased power	7	3	4	133 %	11	9	2	22 %
Adjusted gross margin[4]	140	97	43	44 %	201	198	3	2 %
OM&A[4]	13	13	—	— %	26	26	—	— %
Taxes, other than income taxes	1	1	—	— %	2	2	—	— %
Adjusted EBITDA[4]	126	83	43	52 %	173	170	3	2 %
Depreciation and amortization	(8)	(8)	—	— %	(17)	(15)	(2)	13 %
Adjusted earnings before income taxes[4]	118	75	43	57 %	156	155	1	1 %
Earnings before income taxes	100	74	26	35 %	159	159	—	— %
Supplemental Information:								
Gross revenues per MWh								
Alberta Hydro Assets revenues ($/MWh)[2]	90	68	22	32 %	84	110	(26)	(24)%
Alberta Hydro Assets ancillary services revenues ($/MWh)[1]	42	34	8	24 %	35	44	(9)	(20)%

(1) Alberta Hydro Assets ancillary services revenues is a supplementary financial measure. Alberta Hydro Assets 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 are calculated by dividing Alberta Hydro Assets 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 are 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 of $129 million and $215 million for the three and six months ended June 30, 2025, respectively (June 30, 2024 — $99 million and $211 million), to adjusted gross margin - gross margin of $122 million and $204 million for the three and six months ended June 30, 2025, respectively (June 30, 2024 — $96 million and $202 million), to Adjusted EBITDA and Adjusted earnings before income taxes - earnings before income taxes of $100 million and $159 million for the three and six months ended June 30, 2025, respectively (June 30, 2024 — $74 million and $159 million).

Adjusted revenues for the the three months ended June 30, 2025, increased compared to the same period in 2024, primarily due to:

- Higher environmental and tax attributes revenue due to increased intercompany sales of emission credits to the Gas segment to fulfill our 2024 GHG obligation;
- Higher merchant and ancillary services volumes due to higher availability; and
- Higher ancillary services prices; partially offset by
- Lower spot power prices in the Alberta market.

Adjusted EBITDA and Adjusted earnings before income taxes for the three months ended June 30, 2025, increased compared to the same period in 2024, primarily due to higher adjusted revenues as explained by the factors above.

Earnings before income taxes for the three months ended June 30, 2025, increased compared to the same period in 2024 due to:

- Higher adjusted earnings before income taxes; partially offset by
- Higher unrealized mark-to-market losses due to unfavourable forward pricing changes.

Adjusted revenues for the six months ended June 30, 2025, increased compared to the same period in 2024, primarily due to:

- Higher merchant and ancillary services volumes;
- Higher environmental and tax attributes revenue due to increased intercompany sales of emission credits to the Gas segment to fulfill our 2024 GHG obligation; and
- Higher volume of favourable hedging positions settled; partially offset by
- Lower spot power and ancillary services prices in the Alberta market.

Adjusted EBITDA and Adjusted earnings before income taxes for the six months ended June 30, 2025, increased compared to the same period in 2024, primarily due to higher adjusted revenues as explained by the factors above.

Earnings before income taxes for the six months ended June 30, 2025, increased compared to the same period in 2024 due to higher adjusted earnings before income taxes.

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 June 30				6 months ended June 30			
	2025	2024	Change		2025	2024	Change	
Gross installed capacity (MW)[1]	2,587	2,584	3	— %	2,587	2,584	3	— %
LTA generation (GWh)	1,754	1,618	136	8 %	3,810	3,262	548	17 %
Availability (%)	94.7	94.3	0.4	— %	94.3	93.9	0.4	— %
Production								
Contract production (GWh)	1,292	1,162	130	11 %	2,902	2,316	586	25 %
Merchant production (GWh)	221	337	(116)	(34)%	516	681	(165)	(24)%
Total production (GWh)	1,513	1,499	14	1 %	3,418	2,997	421	14 %
Revenues	90	92	(2)	(2)%	209	194	15	8 %
Environmental and tax attributes revenues	39	30	9	30 %	65	48	17	35 %
Adjusted revenues[2][3]	129	122	7	6 %	274	242	32	13 %
Fuel and purchased power	9	8	1	13 %	19	17	2	12 %
Carbon compliance	1	—	1	— %	2	—	2	— %
Adjusted gross margin[2][3]	119	114	5	4 %	253	225	28	12 %
OM&A[2]	25	24	1	4 %	54	44	10	23 %
Taxes, other than income taxes	5	4	1	25 %	10	8	2	25 %
Adjusted net other operating income[3]	—	(2)	2	(100)%	(2)	(4)	2	(50)%
Adjusted EBITDA[2][3]	89	88	1	1 %	191	177	14	8 %
Depreciation and amortization	(52)	(47)	(5)	11 %	(105)	(90)	(15)	17 %
Adjusted earnings before income taxes[2][3]	37	41	(4)	(10)%	86	87	(1)	(1)%
(Loss) earnings before income taxes[4]	(32)	30	(62)	(207)%	(21)	89	(110)	(124)%

(1) Gross installed capacity for 2025 increased due the transmission adjustments for the White Rock East and Horizon Hill wind facilities of 2 MW each and Tower removal at Sinott in December 2024, which 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 of $56 million and $156 million for the three and six months ended June 30, 2025, respectively (June 30, 2024 — $107 million and $240 million), to adjusted gross margin - gross margin of $46 million and $135 million for the three and six months ended June 30, 2025, respectively (June 30, 2024 — $99 million and $223 million), to adjusted net other operating income - net other operating income of nil and $4 million for the three and six months ended June 30, 2025, respectively (June 30, 2024 — $2 million and $4 million), to adjusted EBITDA and adjusted loss before income taxes - loss before income taxes of $32 million and $21 million for the three and six months ended June 30, 2025, respectively (June 30, 2024 — earnings before income taxes of $30 million and $89 million).

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

Adjusted revenues for the three months ended June 30, 2025, increased compared to the same period in 2024, primarily due to:

- Higher environmental and tax attributes revenue due to the increased sales of emission credits to third parties and intercompany sales to the Gas segment; partially offset by
- Lower tax attributes revenue from the sales agreements to transfer production tax credits from the Oklahoma facilities to taxable U.S. counterparties due to lower wind resource; and
- Lower Alberta pool prices.

Adjusted EBITDA for the three months ended June 30, 2025, increased compared to the same period in 2024, primarily due to higher adjusted revenues as explained by the factors above.

Adjusted earnings before income taxes for the three months ended June 30, 2025, decreased compared to the same period in 2024 due to:

- Higher depreciation and amortization due to the addition of new wind facilities in the first and second quarters of 2024, partially offset by
- Higher adjusted EBITDA as explained above.

Loss before income taxes for the three months ended June 30, 2025, increased from earnings before income taxes in the same period in 2024 due to:

- Lower adjusted earnings before income taxes; and
- Higher unrealized mark-to-market losses on the long-term wind energy sales related to the Garden Plain facilities and changes to wind discount assumptions.

Adjusted revenues for the six months ended June 30, 2025, increased compared to the same period in 2024, primarily due to:

- Full two quarter impact of commercial operation of the White Rock and Horizon Hill wind facilities;
- Higher environmental attributes revenue due to the increased sales of emission credits to third parties and intercompany sales to the Gas segment; and
- Higher production volumes in Eastern Canada due to higher wind resource; and
- Higher tax attributes revenue from the sales agreements to transfer production tax credits from the Oklahoma facilities to taxable U.S. counterparties due to full two quarters of operations; partially offset by
- Lower Alberta pool prices.

Adjusted EBITDA for the six months ended June 30, 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 in the first and second quarters of 2024.

Adjusted earnings before income taxes for the the six months ended June 30, 2025, decreased compared to the same period in 2024 due to:

- Higher depreciation and amortization due to the addition of new wind facilities in the first and second quarters of 2024, partially offset by
- Higher adjusted EBITDA as explained above.

Loss before income taxes for the six months ended June 30, 2025, increased from earnings before income taxes in the same period in 2024 due to:

- Lower adjusted earnings before income taxes; and
- Higher unrealized mark-to-market losses on the long-term wind energy sales related to the Garden Plain and Oklahoma facilities.

Gas

	3 months ended June 30				6 months ended June 30			
	2025	2024	Change		2025	2024	Change	
Gross installed capacity (MW)[1]	4,834	3,087	1,747	57 %	4,834	3,087	1,747	57 %
Availability (%)	90.2	95.3	(5.1)	(5)%	92.9	94.9	(2.0)	(2)%
Production								
Contract sales volume (GWh)	2,197	1,676	521	31 %	4,747	3,398	1,349	40 %
Merchant sales volume (GWh)	580	1,408	(828)	(59)%	1,872	3,453	(1,581)	(46)%
Purchased power (GWh)[2]	(291)	(230)	(61)	27 %	(629)	(469)	(160)	34 %
Total production (GWh)	2,486	2,854	(368)	(13)%	5,990	6,382	(392)	(6)%
Adjusted revenues[3]	282	300	(18)	(6)%	648	646	2	— %
Adjusted fuel and purchased power[3]	105	97	8	8 %	266	239	27	11 %
Carbon compliance[4]	(8)	26	(34)	(131)%	41	66	(25)	(38)%
Adjusted gross margin[3]	185	177	8	5 %	341	341	—	— %
Adjusted OM&A[3]	64	42	22	52 %	121	88	33	38 %
Taxes, other than income taxes	5	3	2	67 %	10	6	4	67 %
Net other operating income	(12)	(10)	(2)	20 %	(22)	(20)	(2)	10 %
Adjusted EBITDA[3][5]	128	142	(14)	(10)%	232	267	(35)	(13)%
Depreciation and amortization	(74)	(56)	(18)	32 %	(138)	(111)	(27)	24 %
Adjusted earnings before income taxes[3]	54	86	(32)	(37)%	94	156	(62)	(40)%
(Loss) earnings before income taxes	(23)	72	(95)	(132)%	42	230	(188)	(82)%

(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 of $204 million and $594 million for the three and six months ended June 30, 2025, respectively (June 30, 2024 — $284 million and $717 million), to adjusted fuel and purchased power - fuel and purchased power of $106 million and $269 million for the three and six months ended June 30, 2025, respectively (June 30, 2024 — $97 million and $239 million), to adjusted gross margin - gross margin of $106 million and $284 million for the three and six months ended June 30, 2025, respectively (June 30, 2024 — $161 million and $412 million), to adjusted OM&A - OM&A of $65 million and $124 million for the three and six months ended June 30, 2025, respectively (June 30, 2024 — $42 million and $88 million), to adjusted EBITDA and adjusted earnings before income taxes - loss before income taxes of $23 million and earnings before income taxes of $42 million for the three and six months ended June 30, 2025, respectively (June 30, 2024 — earnings before income taxes of $72 million and $230 million).

(4) Carbon compliance includes the impact of utilizing credits for the 2024 obligation settlement occurring during the three months ended June 30, 2025.

(5) 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 June 30, 2025, decreased compared to the same period in 2024, primarily due to:

- 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; partially offset by
- Addition of gas facilities from Heartland.

Adjusted EBITDA for the three months ended June 30, 2025, decreased compared to the same period in 2024, primarily due to lower adjusted revenues as explained by the factors above and was further impacted by:

- Higher OM&A related to the addition of the Heartland facilities;
- Higher natural gas prices;
- An increase in the carbon price from $80 to $95 per tonne, impacting gross margin from our Canadian gas facilities; partially offset by
- Utilization of higher quantity of internally generated emission credits in the current period compared to the same period of prior year to settle a portion of our 2024 GHG obligation and a portion of the GHG obligation assumed in the Heartland acquisition.

Adjusted earnings before income taxes for the three months ended June 30, 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.

Loss before income taxes for the three months ended June 30, 2025 increased due to:

- Higher unrealized mark-to-market losses due to less favourable hedges in the current period compared to the same period in 2024; and
- Lower adjusted earnings before income taxes compared to the same period in 2024.

Adjusted revenues for the six months ended June 30, 2025, increased compared to the same period in 2024, primarily due to:

- Addition of gas facilities from Heartland; and
- Higher volume of 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 six months ended June 30, 2025, decreased compared to the same period in 2024, primarily due to due to:

- Higher OM&A related to the addition of the Heartland facilities;
- Higher natural gas prices;
- An increase in the carbon price from $80 to $95 per tonne, impacting gross margin from our Canadian gas facilities; partially offset by
- Utilization of higher quantity of internally generated emission credits in the current period compared to the same period of prior year to settle a portion of our 2024 GHG obligation and a portion of the GHG obligation assumed in the Heartland acquisition.

Adjusted earnings before income taxes for the six months ended June 30, 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 six months ended June 30, 2025 decreased due to:

- Higher unrealized mark-to-market losses due to less favourable hedges in the current period compared to the same periods in 2024;
- Lower adjusted earnings before income taxes compared to the same period in 2024; 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 June 30				6 months ended June 30			
	2025	2024	Change		2025	2024	Change	
Gross installed capacity (MW)	671	671	—	— %	671	671	—	— %
Availability (%)	81.3	59.0	22.3	38 %	89.1	69.0	20.1	29 %
Production								
Contract sales volume (GWh)	655	829	(174)	(21)%	1,303	1,659	(356)	(21)%
Merchant sales volume (GWh)	283	44	239	543 %	1,386	977	409	42 %
Purchased power (GWh)(1)	(696)	(871)	175	(20)%	(1,407)	(1,833)	426	(23)%
Total production (GWh)	242	2	240	12000 %	1,282	803	479	60 %
Adjusted revenues(2)	88	65	23	35 %	241	276	(35)	(13)%
Fuel and purchased power	51	46	5	11 %	149	212	(63)	(30)%
Adjusted gross margin(2)	37	19	18	95 %	92	64	28	44 %
OM&A	18	15	3	20 %	35	33	2	6 %
Taxes, other than income taxes	—	2	(2)	(100)%	1	2	(1)	100 %
Adjusted EBITDA(2)(3)	19	2	17	850 %	56	29	27	93 %
Depreciation and amortization	(13)	(15)	2	(13)%	(28)	(31)	3	(10)%
Adjusted earnings (loss) before income taxes(2)	6	(13)	19	(146)%	28	(2)	30	(1500)%
(Loss) earnings before income taxes	(20)	3	(23)	(767)%	27	23	4	17 %
Supplemental information:								
Highvale mine reclamation spend(4)	3	3	—	— %	6	6	—	— %
Centralia mine reclamation spend(4)	4	4	—	— %	8	7	1	14 %

(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 (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 of $73 million and $227 million for the three and six months ended June 30, 2025, respectively (June 30, 2024 — $79 million and $296 million), to adjusted gross margin - gross margin $22 million and $78 million for the three and six months ended June 30, 2025, respectively (June 30, 2024 — $33 million and $84 million), to Adjusted EBITDA and Adjusted earnings (loss) before income taxes - loss before income taxes $20 million and earnings before income taxes of $27 million for the three and six months ended June 30, 2025, respectively (June 30, 2024 — earnings before income taxes of $3 million and $23 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 June 30, 2025, increased compared to the same period in 2024, primarily due to higher production driven by higher Mid-Columbia prices and higher availability.

Adjusted EBITDA and Adjusted earnings (loss) before income taxes for the three months ended June 30, 2025, increased compared to the same period in 2024, primarily due to higher adjusted revenues as explained above.

Loss before income taxes for the three months ended June 30, 2025, increased compared to earnings before income taxes for the same period in 2024 due to:

- Higher unrealized mark-to-market losses due to less favourable hedges in the current period; and
- Higher asset impairment charges related to an increase in decommissioning and restoration provision on retired assets driven by a decrease in discount rates; partially offset by
- Higher adjusted earnings before income taxes as explained above.

Mine reclamation spend for the three months ended June 30, 2025, was consistent with the same period in 2024.

Adjusted revenues for the six months ended June 30, 2025, decreased compared to the same period in 2024, primarily due to lower Mid-Columbia prices.

Adjusted EBITDA for the six months ended June 30, 2025, increased 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 adjusted revenues as explained above.

Adjusted earnings before income taxes for the six months ended June 30, 2025, increased compared to the same period in 2024 due to higher adjusted EBITDA as explained above.

Earnings before income taxes for the six months ended June 30, 2025, increased compared to the same period in 2024 due to:

- Higher adjusted earnings before income taxes as explained above;
- Impairment reversal related to generation equipment in the current period; partially offset by
- Higher unrealized mark-to-market losses due to less favourable hedges in the current period; and
- Higher asset impairment charges related to an increase in decommissioning and restoration provision on retired assets driven by a decrease in discount rates.

Mine reclamation spend for the six months ended June 30, 2025, was consistent with the same period in 2024.

Energy Marketing

	3 months ended June 30				6 months ended June 30			
	2025	2024	Change		2025	2024	Change	
Adjusted revenues(1)	34	48	(14)	(29)%	62	97	(35)	(36)%
OM&A	8	9	(1)	(11)%	15	19	(4)	(21)%
Adjusted EBITDA(1)(2)	26	39	(13)	(33)%	47	78	(31)	(40)%
Depreciation and amortization	—	(1)	1	(100)%	(2)	(2)	—	— %
Adjusted earnings before income taxes(1)(2)	26	38	(12)	(32)%	45	76	(31)	(41)%
Earnings before income taxes	30	37	(7)	(19)%	48	78	(30)	(38)%

(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 for the three and six months ended June 30, 2025 is revenues of $38 million and $65 million, respectively (June 30, 2024 — $47 million and $99 million), to Adjusted EBITDA and Adjusted earnings before income taxes - earnings before income taxes of $30 million and $48 million, respectively (June 30, 2024 — $37 million and $78 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 and six months ended June 30, 2025, decreased compared to the same periods in 2024, primarily due to:

- Comparatively subdued market volatility across North American natural gas and power markets; and
- Lower realized settled trades in 2025 in comparison to the same periods in the prior year.

Adjusted earnings before income taxes for the three and six months ended June 30, 2025, decreased compared to the same periods in 2024 mainly due to lower adjusted revenues as explained above.

Earnings before income taxes for the three and six months ended June 30, 2025, decreased compared to the same periods in 2024 due to lower adjusted earnings before income taxes.

Corporate

	3 months ended June 30				6 months ended June 30			
	2025	**2024**	**Change**		**2025**	**2024**	**Change**	
Adjusted OM&A[1]	**38**	**38**	*—*	*—%*	**79**	**63**	*16*	*25%*
Taxes, other than income taxes	**1**	**—**	*1*	*100%*	**1**	**—**	*1*	*100%*
Adjusted EBITDA[1]	**(39)**	**(38)**	*(1)*	*3 %*	**(80)**	**(63)**	*(17)*	*27 %*
Depreciation and amortization	**(4)**	**(5)**	*1*	*(20)%*	**(9)**	**(9)**	*—*	*— %*
Equity income from associate	**—**	**1**	*(1)*	*(100)%*	**(1)**	**(1)**	*—*	*— %*
Interest income	**7**	**8**	*(1)*	*(13)%*	**12**	**15**	*(3)*	*(20)%*
Interest expense	**(89)**	**(80)**	*(9)*	*11 %*	**(183)**	**(149)**	*(34)*	*23 %*
Realized foreign exchange gain (loss)[2]	**6**	**(1)**	*7*	*(700%)*	**2**	**(9)**	*11*	*(122%)*
Adjusted loss before income taxes[1]	**(119)**	**(115)**	*(4)*	*3 %*	**(259)**	**(216)**	*(43)*	*20 %*
Loss before income taxes	**(150)**	**(122)**	*(28)*	*23%*	**(301)**	**(218)**	*(83)*	*38%*

(1) 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 OM&A for the three and six months ended June 30, 2025 is OM&A of $45 million and $94 million, respectively (June 30, 2024 — $42 million and $70 million). The most directly comparable IFRS measure to adjusted EBITDA and adjusted earnings (loss) before income taxes is loss before income taxes of $150 million and $301 million for the three and six months ended June 30, 2025, respectively (June 30, 2024 — $122 million and $218 million).

(2) Realized foreign exchange gain (loss) is a supplementary financial measure. Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A for more details.

Adjusted EBITDA for the three and six months ended June 30, 2025, decreased compared to the same periods 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 and six months ended June 30, 2025, increased compared to the same periods in 2024 due to:

- Lower Adjusted EBITDA as explained above; and
- Higher interest expense due to lower capitalized interest resulting from lower construction activity during 2025 compared to the same periods in 2024 and higher credit facility fees in the current period; partially offset by
- Higher realized foreign exchange gains due to hedges settled during the period at favourable foreign currency rates.

Loss before income taxes for the three and six months ended June 30, 2025, increased compared to the same periods in 2024 due to:

- Higher adjusted loss before income taxes as explained above;
- Higher unrealized foreign exchange losses due to unfavorable changes in foreign currency rates; and
- Higher spending related to the planning and design of an upgrade to our ERP system.

Performance by Segment with Supplemental Geographical Information

The following tables provide adjusted EBITDA by segment across the regions we operate in:

3 months ended June 30, 2025	Hydro	Wind & Solar[3]	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	120	21	76	(3)	26	(39)	201
Canada, excluding Alberta	6	32	27	—	—	—	65
US	—	34	2	22	—	—	58
Western Australia	—	2	23	—	—	—	25
Adjusted EBITDA[1]	**126**	**89**	**128**	**19**	**26**	**(39)**	**349**
Adjusted earnings (loss) before income taxes[1]	**118**	**37**	**54**	**6**	**26**	**(119)**	**122**
Earnings (loss) before income taxes	**100**	**(32)**	**(23)**	**(20)**	**30**	**(150)**	**(95)**

3 months ended June 30, 2024	Hydro	Wind & Solar[3]	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	80	16	92	(2)	39	(38)	187
Canada, excluding Alberta	3	28	26	—	—	—	57
US	—	42	3	4	—	—	49
Western Australia	—	2	21	—	—	—	23
Adjusted EBITDA[1][2]	83	88	142	2	39	(38)	316
Adjusted earnings (loss) before income taxes[1]	75	41	86	(13)	38	(115)	112
Earnings (loss) before income taxes	74	30	72	3	37	(122)	94

(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. 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.

6 months ended June 30, 2025	Hydro	Wind & Solar[3]	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	167	31	126	(5)	47	(80)	286
Canada, excluding Alberta	6	80	54	—	—	—	140
U.S.	—	76	5	61	—	—	142
Western Australia	—	4	47	—	—	—	51
Adjusted EBITDA[1]	**173**	**191**	**232**	**56**	**47**	**(80)**	**619**
Adjusted earnings (loss) before income taxes[1]	**156**	**86**	**94**	**28**	**45**	**(259)**	**150**
Earnings (loss) before income taxes	**159**	**(21)**	**42**	**27**	**48**	**(301)**	**(46)**

6 months ended June 30, 2024	Hydro	Wind & Solar[3]	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	167	40	167	(5)	78	(63)	384
Canada, excluding Alberta	3	68	50	—	—	—	121
U.S.	—	65	6	34	—	—	105
Western Australia	—	4	44	—	—	—	48
Adjusted EBITDA[1][2]	170	177	267	29	78	(63)	658
Adjusted earnings (loss) before income taxes[1]	155	87	156	(2)	76	(216)	256
Earnings (loss) before income taxes	159	89	230	23	78	(218)	361

(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. 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 and transmission capacity. We believe that the fast-ramping nature of certain Heartland facilities is well positioned to respond to price volatility and deliver peaking capacity during 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 installed 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 and second quarters of 2025, there were periods of low market prices, and the Company opted not to generate production from its 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. Such services are provided in the event of a system-wide blackout in the province, as well as 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 June 30	**Hydro**	**Wind & Solar[4]**	**Gas[5]**	**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)	433	440	1,593	—	2,466	340	537	1,842	—	2,719
Contract production (GWh)	—	219	1,148	—	1,367	—	287	593	—	880
Merchant production (GWh)	433	221	445	—	1,099	340	250	1,249	—	1,839
Hedged volumes (GWh)	327	28	1,513	—	1,868	110	34	1,988	—	2,132
Production contracted or hedged (%)	76%	56%	167%	—%	131%	32%	60%	140%	—%	111%
Hedged volumes as a percentage of gross installed capacity (%)	18%	2%	19%	—%	16%	6%	2%	46%	—%	27%
Adjusted revenues[2][3] ($)	137	36	170	1	344	94	29	193	2	318
Fuel ($)	2	3	62	—	67	1	4	60	—	65
Purchased power ($)	4	—	14	—	18	2	—	10	—	12
Carbon compliance cost (recovery)[3]	—	1	(13)	—	(12)	—	—	21	1	22
Adjusted gross margin[2] ($)	131	32	107	1	271	91	25	102	1	219

(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 and Wind and Solar segments 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 Wind and Solar was reduced due to tower removal at Sinott.

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

Three months ended June 30, 2025 Variance Analysis (2025 versus 2024)

Total production for the Alberta portfolio for the three months ended June 30, 2025, was 2,466 GWh compared to 2,719 GWh in the same period of 2024. The decrease of 253 GWh, or nine per cent was primarily due to:

- Lower merchant production in the Gas segment due to higher dispatch optimization driven by lower market prices; and
- Lower production volumes in the Wind and Solar segment due to lower wind resource in the second quarter of 2025; partially offset by
- Higher contract production in the Gas segment due to the addition of Heartland gas facilities in the fourth quarter of 2024; and
- Higher production from the Hydro segment due to the optimization of water supply to facilitate generation during higher demand periods.

Hedged volumes for the three months ended June 30, 2025, decreased compared to the same period in 2024 due to lower production volumes overall. Realized gains and losses on financial hedges are included in adjusted revenues in the table above.

Adjusted gross margin for the Alberta portfolio for the three months ended June 30, 2025, was $271 million compared to $219 million in the same period of 2024. The increase of $52 million, or 24 per cent, was primarily due to:

- Positive contribution from the addition of the Heartland facilities in the Gas segment;
- Higher environmental and tax attributes revenue due to increased sales of emission credits to third parties and intercompany sales from the Hydro and Wind and Solar segments to the Gas segment;
- Carbon compliance recovery in the current period due to lower production in the Gas segment and utilization of higher quantity of internally generated emission credits in the current period compared to the same period of prior year to settle a portion of our 2024 GHG obligation and a portion of the GHG obligation assumed in the Heartland acquisition; and
- Higher ancillary services revenues in the Hydro segment due to higher demand by the AESO; partially offset by
- The impact of lower Alberta spot prices;
- Lower merchant production in the Gas segment due to higher dispatch optimization driven by lower market prices;
- Lower gains realized on financial hedges settled in the period; and
- An increase in the carbon price per tonne from $80 in 2024 to $95 in 2025.

	2025					2024				
6 months ended June 30	**Hydro**	**Wind & Solar(4)**	**Gas(5)**	**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)	778	997	3,886	—	5,661	653	1,031	4,207	—	5,891
Contract production (GWh)	—	481	2,518	—	2,999	—	526	1,201	—	1,727
Merchant production (GWh)	778	516	1,368	—	2,662	653	505	3,006	—	4,164
Hedged volumes (GWh)	602	66	3,579	—	4,247	194	70	3,813	—	4,077
Production contracted or hedged (%)	77%	55%	157%	—%	128%	30%	58%	119%	—%	99%
Hedged volumes as a percentage of gross installed capacity (%)	33%	4%	45%	—%	37%	5%	2%	44%	—%	34%
Adjusted revenues(2)(3) ($)	199	64	396	3	662	197	67	429	3	696
Fuel ($)	3	7	161	—	171	3	7	146	—	156
Purchased power ($)	7	1	25	—	33	5	1	34	—	40
Carbon compliance costs(3) ($)	—	2	23	—	25	—	—	57	1	58
Adjusted gross margin(2) ($)	189	54	187	3	433	189	59	192	2	442

(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 and Wind and Solar segments 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 Wind and Solar was reduced due to tower removal at Sinott.

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

Six months ended June 30, 2025 Variance Analysis (2025 versus 2024)

Total production for the Alberta portfolio for the six months ended June 30, 2025, 5,661 GWh compared to 5,891 GWh in the same period of 2024. The decrease of 230 GWh, or four per cent was primarily due to:

- Lower merchant production in the Gas segment due to higher dispatch optimization driven by lower market prices; and
- Lower production volumes in the Wind and Solar segment due to lower wind resource compared to the same period in 2024; partially offset by
- Higher contract production in the Gas segment due to the addition of Heartland gas facilities in the fourth quarter of 2024; and
- Higher production from the Hydro segment due to higher water resource and the optimization of water supply to facilitate generation during higher demand periods.

Hedged volumes for the six months ended June 30, 2025, increased compared to the same period in 2024. The Company deployed a defensive strategy to increase financial hedges for the merchant portfolio at attractive margins in anticipation of the risk of lower prices in 2025. Realized gains and losses on financial hedges are included in adjusted revenues in the table above.

Adjusted gross margin for the Alberta portfolio for the six months ended June 30, 2025 was $433 million compared to $442 million in the same period of 2024. The decrease of $9 million, or two per cent, was primarily due to:

- The impact of lower Alberta spot and ancillary services prices;
- Lower merchant production in the Gas segment due to higher dispatch optimization driven by lower market prices; and
- Higher fuel costs in the Gas segment due to higher natural gas prices;
- An increase in the carbon price from $80 per tonne in 2024 to $95 per tonne in 2025; partially offset by
- Positive contribution from the addition of the Heartland facilities in the Gas segment;
- Higher gains realized on financial hedges settled in the period;
- Lower carbon compliance costs in the current period due to lower production in the Gas segment and utilization of higher quantity of internally generated emission credits in the current period compared to the same period of prior year to settle a portion of our 2024 GHG obligation and a portion of the GHG obligation assumed in the Heartland acquisition;
- Higher environmental and tax attributes revenue due to increased sales of emission credits to third parties and intercompany sales from the Hydro and Wind and Solar segments to the Gas segment;
- Higher ancillary services volumes produced in the Hydro segment due to higher demand by the AESO; and
- Lower purchased power costs due to lower Alberta spot prices.

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

	3 months ended June 30		6 months ended June 30	
	2025	**2024**	**2025**	**2024**
Alberta Market				
Spot power price average per MWh	**40**	45	**40**	72
Natural gas price (AECO) per GJ	**1.64**	1.14	**1.83**	1.54
Carbon compliance price per tonne	**95**	80	**95**	80
Alberta Portfolio Results				
Realized merchant power price per MWh(1)	**111**	97	**111**	105
Hydro energy spot power price per MWh	**82**	58	**77**	103
Hydro ancillary services price per MWh	**42**	34	**35**	44
Wind energy spot power price per MWh	**23**	31	**21**	41
Gas spot power price per MWh	**61**	56	**57**	89
Hedged power price average per MWh(2)	**70**	84	**70**	86
Hedged volume (GWh)	**1,868**	2,132	**4,247**	4,077
Fuel cost per MWh(3)	**42**	35	**44**	42
Carbon compliance (recovery) cost per MWh(4)	**(8)**	11	**6**	13

(1) Realized merchant power price per MWh for the Alberta electricity portfolio is a supplementary financial measure and represents the average price realized as a result of the Company's merchant power sales and portfolio optimization activities. It is calculated as merchant revenues (excluding assets under long-term contract and ancillary revenues) for the reporting period divided by total merchant GWh produced during the reporting period.

(2) Hedged power price average per MWh is a supplementary financial measure and 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 and six months ended June 30, 2025, decreased from $45 and $72 per MWh, respectively, in 2024, to $40 per MWh in both the three and six months ended June 30, 2025, primarily due to milder weather and the addition of increased supply from renewables and combined-cycle gas facilities into the market compared to the same periods in 2024.

The realized merchant power price per MWh of production for the Alberta portfolio for the three and six months ended June 30, 2025, increased by $14 and $6 per MWh, respectively, compared to the same periods in 2024, primarily due to:

- Favourable hedge positions settling in the current period, which generated positive contributions over settled spot prices in Alberta compared to the same periods in 2024; partially offset by
- Lower average spot power prices as explained above.

Fuel cost per MWh for the three and six months ended June 30, 2025, increased by $7 and $2 per MWh, respectively, compared to the same periods in 2024, primarily due to higher natural gas prices.

Carbon compliance cost per MWh of production for the three and six months ended June 30, 2025, decreased by $19 and $7 per MWh, respectively, compared to the same periods in 2024, primarily due to:

- Higher utilization of emission credits to settle a portion of our 2024 GHG obligation and a portion of GHG obligation assumed in the Heartland acquisition; partially offset by
- An increase in the carbon price per tonne from $80 in 2024 to $95 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.

	Q3 2024	Q4 2024	Q1 2025	Q2 2025
Revenues	638	678	758	**433**
Carbon compliance costs (recovery)	41	39	49	**(74)**
OM&A	143	234	173	**173**
Depreciation and amortization	133	143	146	**150**
Earnings (loss) before income taxes	9	(51)	49	**(95)**
Net earnings (loss) attributable to common shareholders	(36)	(65)	46	**(112)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	(0.12)	(0.22)	0.15	**(0.38)**
Cash flow from operating activities	229	215	7	**157**

	Q3 2023	Q4 2023	Q1 2024	Q2 2024
Revenues	1,017	624	947	582
Carbon compliance costs (recovery)	28	27	40	(8)
OM&A	131	150	134	144
Depreciation and amortization	140	132	124	131
Earnings (loss) before income taxes	453	(35)	267	94
Net earnings (loss) attributable to common shareholders	372	(84)	222	56
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	1.41	(0.27)	0.72	0.18
Cash flow from operating activities	681	310	244	108

(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 and second quarters 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 each quarter of 2024, compared to the same periods in the prior years primarily due to the impact of additions of new natural gas, wind and solar supply in the Alberta market;
- Higher realized pricing in the first and second quarters of 2025 compared to the same periods in the prior year due to favourable hedge positions settling in the current period, which generated positive contributions over settled spot prices and and lower average spot power prices as explained above.

Carbon compliance costs (recovery) have been impacted by:

- Higher costs of carbon per tonne, which increased from $80 in 2024 to $95 in 2025;
- In the second quarter of 2025, carbon compliance costs were reduced by using internally generated and externally purchased emission credits to settle a portion of our 2024 GHG obligation and a portion of the GHG obligation assumed in the Heartland acquisition; 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 our 2023 GHG obligation.

OM&A has been impacted by:

- Higher spending to support strategic and growth initiatives in the first and second quarters of 2025 and in all four quarters of 2024, compared to same periods in the prior year;
- Return to service of the Kent Hills wind facilities and the addition of the Horizon Hill and White Rock wind facilities in the first and second quarters of 2024;
- The addition of the Heartland facilities and associated corporate costs in the first and second quarters of 2025 and fourth quarter of 2024;
- Higher costs stemming from planning and design of an upgrade to our ERP system in the first and second quarters 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 Divestitures classified as held for sale in the first quarter of 2025;
- Development projects that are no longer proceeding in the first and second quarters of 2025 and 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;
- Increase in decommissioning provisions for retired assets due to a decrease in discount rates in the second quarter of 2025;
- 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 associated with the Planned Divestitures; and
- Higher interest expense due to lower capitalized interest during 2025 as a result of lower capital activity in the first and second quarters of 2025 and higher credit facility fees in the current period compared to the same periods in 2024.

Net earnings (loss) attributable to common shareholders has been impacted by fluctuations in current and deferred tax expense with earnings (loss) 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 and second quarters 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;
- Higher unrealized foreign exchange losses in the second quarter of 2025 compared to the same period in 2024; 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.

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.

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.

Maintain Financial Strength and Capital Discipline

The Company maintains a strong financial position, with $1.5 billion in liquidity as of June 30, 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, on Feb. 19 2025, the Company's Board of Director's approved the increase to the common share dividend by eight per cent to $0.26 per share, our sixth consecutive annual dividend increase. 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 and first half of 2025, we refined our development pipeline to align with evolving regulatory and interconnection dynamics, while progressing opportunities at our legacy assets. The pipeline now includes 475 MW of mid-stage projects and 4,078 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 advanced 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	1,625	983	230	1,240	4,078

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	150	—	335
Western Australia	—	—	40	—	40
Total	—	285	190	—	475

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$32	Q4 2025	13	• All major equipment delivered and installed • On-track to be completed on schedule
Total(1)			**n/a**	**$34 —**	**$36**	**$19**			

(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 June 30, 2025:

	June 30, 2025	Dec. 31, 2024	Increase/(decrease)
Assets			
Current assets			
Cash and cash equivalents	**222**	337	(115)
Risk management assets	**108**	318	(210)
Other current assets[1]	**1,113**	1,118	(5)
Total current assets	**1,443**	1,773	(330)
Non-current assets			
Risk management assets	**36**	93	(57)
Property, plant and equipment, net	**5,798**	6,020	(222)
Long-term financial assets	**100**	—	100
Other non-current assets[2]	**1,562**	1,613	(51)
Total non-current assets	**7,496**	7,726	(230)
Total assets	**8,939**	9,499	(560)
Liabilities			
Current liabilities			
Accounts payable, accrued liabilities and other current liabilities	**573**	756	(183)
Risk management liabilities	**168**	277	(109)
Dividends payable	**19**	49	(30)
Credit facilities, long-term debt and lease liabilities	**168**	572	(404)
Contingent consideration payable	**49**	81	(32)
Other current liabilities[3]	**851**	834	17
Total current liabilities	**1,828**	2,569	(741)
Non-current liabilities			
Credit facilities, long-term debt and lease liabilities	**3,593**	3,236	357
Decommissioning and other provisions (long-term)	**864**	850	14
Risk management liabilities (long-term)	**349**	305	44
Other non-current liabilities[4]	**642**	696	(54)
Total non-current liabilities	**5,448**	5,087	361
Total liabilities	**7,276**	7,656	(380)
Equity			
Equity attributable to shareholders	**1,579**	1,746	(167)
Non-controlling interests	**84**	97	(13)
Total equity	**1,663**	1,843	(180)
Total liabilities and equity	**8,939**	9,499	(560)

(1) Other current assets is a supplementary financial measure and consists of restricted cash of $52 million (Dec. 31, 2024 — $69 million), trade and other receivables of $765 million (Dec. 31, 2024 — $767 million), prepaid expenses and other of $84 million (Dec. 31, 2024 — $68 million), inventory of $135 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 the long-term portion of finance lease receivables of $289 million (Dec. 31, 2024 — $305 million), right-of-use assets of $115 million (Dec. 31, 2024 — $120 million), intangible assets of $265 million (Dec. 31, 2024 — $281 million), goodwill of $516 million (Dec. 31, 2024 — $517 million), deferred income tax assets of $68 million (Dec. 31, 2024 — $52 million), investments of $141 million (Dec. 31, 2024 — $159 million) and other assets of $168 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 $101 million (Dec. 31, 2024 — $83 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 of $25 million (Dec. 31, 2024 — $24 million), defined benefit obligation and other long-term liabilities of $180 million (Dec. 31, 2024 — $202 million) and deferred income taxes of $437 million (Dec. 31, 2024 — $470 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 $385 million as at June 30, 2025 (Dec. 31, 2024 — $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 $330 million to $1,443 million as at June 30, 2025, from $1,773 million as at Dec. 31, 2024, primarily due to:

- Lower risk management assets mainly due to lower market prices across multiple markets and contract settlements; and
- Lower cash and cash equivalents mainly due to lower cash flow from operating activities and higher cash used in investing activities.

Current liabilities decreased by $741 million to $1,828 million as at June 30, 2025, from $2,569 million as at Dec. 31, 2024, mainly due to:

- Lower current portion of credit facilities, long-term debt and lease liabilities mainly due to advance repayment of the variable rate term loan facility;
- Lower risk management liabilities due to lower market prices and contract settlements;
- Lower accounts payable, accrued liabilities and other current liabilities mainly due to lower cost accruals and lower capital spending;
- Lower contingent consideration payable related to the Planned Divestitures due to changes in fair value; and
- Lower dividends payable due to the timing of payments.

Non-Current Assets

Non-current assets as at June 30, 2025, were $7,496 million, a decrease of $230 million from $7,726 million as at Dec. 31, 2024, primarily due to:

- Lower property, plant and equipment (PP&E) resulting from depreciation of $281 million in the first and second quarters of 2025 and transfers to assets held for sale related to Energy transition equipment of $31 million, partially offset by capital additions of $105 million related to major maintenance for our Canadian gas facilities due to timing of spend and the addition of maintenance for the gas facilities acquired from Heartland; and
- Lower risk management assets due to unfavorable changes in market prices and volatility across multiple markets; 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.

Non-Current Liabilities

Non-current liabilities as at June 30, 2025 were $5,448 million, an increase of $361 million from $5,087 million as at Dec. 31, 2024, mainly due to:

- An increase in credit facilities, long-term debt and lease liabilities due to the $450 million senior notes offering on March 24, 2025; and
- Higher risk management liabilities due to forward price changes and volatility in market pricing across multiple markets; partially offset by
- A decrease in decommissioning and other provisions due to revisions in discount rates and estimated decommissioning costs.

Total Equity

Total equity at June 30, 2025, decreased by $180 million due to:

- Net losses of $64 million;
- Net losses on derivatives designated as cash flow hedges of $56 million;
- Dividends declared on common and preferred shares of $32 million; and
- Share repurchases under the NCIB of $24 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:

	June 30, 2025		Dec. 31, 2024	
	$	%	$	%
Net senior unsecured debt				
Recourse debt - CAD debentures	**697**	**12**	251	4
Recourse debt - U.S. senior notes	**947**	**16**	995	16
Credit facilities	**201**	**3**	543	9
Less: Cash and cash equivalents	**(222)**	**(4)**	(337)	(6)
Add: Bank overdraft	**—**	**—**	1	—
Less: Fair value of foreign exchange forward contracts on foreign-currency denominated debt(1)	**2**	**—**	(7)	—
Exchangeable debentures	**350**	**6**	350	6
Non-recourse debt				
TAPC Holdings LP bond (Poplar Creek)	**70**	**1**	75	1
Pingston bond	**39**	**1**	39	1
Melancthon Wolfe Wind LP bond	**116**	**2**	133	2
New Richmond Wind LP bond	**89**	**1**	93	2
Kent Hills Wind LP bond	**172**	**3**	179	3
Windrise Wind LP bond	**154**	**3**	157	3
TEC Hedland PTY Ltd bond	**661**	**11**	675	11
Heartland term facility	**204**	**3**	224	4
Recourse debt				
TransAlta OCP LP bond	**180**	**3**	192	3
Less: TransAlta OCP LP restricted cash(2)	**—**	**—**	(17)	—
Tax equity financing	**85**	**1**	101	1
Lease liabilities	**147**	**2**	151	2
Total consolidated net debt(3)(4)(5)	**3,892**	**64**	3,798	62
Exchangeable preferred shares(5)	**400**	**7**	400	7
Equity attributable to shareholders				
Common shares	**3,166**	**53**	3,179	53
Preferred shares	**942**	**16**	942	16
Contributed surplus, deficit and accumulated other comprehensive loss	**(2,529)**	**(41)**	(2,375)	(40)
Non-controlling interests	**84**	**1**	97	2
Total capital	**5,955**	**100**	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 is a non-IFRS measure, which 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 of $3,761 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 $571 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 into an equity ownership interest in TransAlta's Alberta Hydro Assets as of Dec. 31, 2024.

Credit Facilities

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

As at June 30, 2025		Utilized			
Credit facilities	**Facility size**	**Outstanding letters of credit(1)**	**Cash drawings**	**Available capacity**	**Maturity date**
Committed					
Syndicated credit facility	1,950	391	203	1,356	Q2 2028
Bilateral credit facilities	240	153	—	87	Q2 2026
Heartland credit facilities	256	26	204	26	Q4 2027
Heartland Export Development Canada letter of credit facility	30	14	—	16	Q4 2025
Total Committed	**2,476**	**584**	**407**	**1,485**	
Non-Committed					
Demand facilities	400	210	—	190	N/A
Total Non-Committed	**400**	**210**	**—**	**190**	

(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 $210 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 $222 million of available cash and cash equivalents as at June 30, 2025.

TransAlta's debt has terms and conditions, including financial covenants, that are considered ordinary and customary. As at June 30, 2025, the Company was in compliance with all of its debt covenants.

Credit Facility Extension

On July 16, 2025, the Company executed agreements to extend committed credit facilities totalling $2.1 billion with a syndicate of lenders. Refer to the Significant and Subsequent Events section of this MD&A for more information.

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 second quarter of 2025.

As at June 30, 2025, $6 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 June 30		6 months ended June 30	
	2025	**2024**	**2025**	**2024**
Interest income	**6**	8	**11**	15
Interest on debt	**51**	50	**102**	99
Interest on exchangeable debentures	**6**	8	**12**	15
Interest on exchangeable preferred shares	**7**	7	**14**	14
Capitalized interest	**—**	(2)	**—**	(16)
Interest on lease liabilities	**4**	3	**9**	5
Credit facility fees, bank charges and other interest	**6**	2	**15**	8
Accretion of provisions	**14**	12	**29**	24
Interest expense	**88**	80	**181**	149

Interest income was lower due to lower average cash balances and lower interest rates in the current period compared to the same periods in 2024. Interest expense was higher than in the same periods of 2024, primarily due to lower capitalized interest resulting from lower construction activity in the six months ended June 30, 2025 compared to the same period in 2024 and higher credit facility fees in the current period.

Share Capital

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

	Number of shares (millions)		
As at	**July 31, 2025**	**June 30, 2025**	**Dec. 31, 2024**
Common shares issued and outstanding, end of period	**296.4**	**296.4**	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 June 30, 2025, the Company owned 50.01 per cent of TA Cogen (June 30, 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 June 30, 2025, the Company owned 83 per cent of Kent Hills Wind LP (June 30, 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 and six months ended June 30, 2025, decreased by $4 and $24 million, respectively, compared to the same periods 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 six months ended June 30, 2025, decreased by $129 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 six months ended June 30, 2025 and June 30, 2024:

6 months ended June 30	2025	2024	Increase/ (decrease)
Cash and cash equivalents, beginning of period	**337**	348	(11)
Provided by (used in):			
Operating activities	**164**	352	(188)
Investing activities	**(201)**	(105)	(96)
Financing activities	**(77)**	(247)	170
Translation of foreign currency cash	**(1)**	3	(4)
Cash and cash equivalents, end of period	**222**	351	(129)

Cash Flow from Operating Activities

Cash from operating activities for the six months ended June 30, 2025, decreased compared with the same period in 2024, primarily due to the following:

	6 months ended June 30
Cash flow from operating activities for the six months ended June 30, 2024	352
Lower gross margin due to lower revenues, partially offset by lower fuel and purchased power costs and carbon compliance recovery in the current period.	(254)
Higher unrealized losses from risk management activities compared to unrealized gains in the same period in 2024.	276
Higher OM&A due to increased spending on strategic and growth initiatives, the addition of the Heartland facilities and associated corporate costs, the full two quarter impact from 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.	(68)
Higher interest expense primarily due to lower capitalized interest resulting from lower construction activity in the first and second quarters of 2025 and higher credit facility fees compared to the same periods in 2024.	(19)
Unfavourable change in non-cash operating working capital balances due to lower accounts payable and accrued liabilities, higher accounts receivable, higher income taxes receivable, partially offset by lower collateral provided.	(91)
Other non-cash items	(32)
Cash flow from operating activities for the six months ended June 30, 2025	**164**

Cash Flow used in Investing Activities

Cash used in investing activities for the six months ended June 30, 2025, increased compared with the same period in 2024, primarily due to the following:

	6 months ended June 30
Cash flow used in investing activities for the six months ended June 30, 2024	(105)
Lower additions to PP&E due to larger construction program in the first and second quarters of 2024 compared to the current period.	21
Favourable change in non-cash investing working capital balances due to lower capital accruals.	23
Long-term financial assets were issued during the first quarter of 2025.	(107)
Other[1]	(33)
Cash flow used in investing activities for the six months ended June 30, 2025	**(201)**

(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 six months ended June 30, 2025, decreased compared with the same period in 2024, primarily due to the following:

	6 months ended June 30
Cash flow used in financing activities for the six months ended June 30, 2024	(247)
Repayment of the $400 million variable rate term facility.	(400)
Issuance of $450 million senior notes during the first quarter of 2025.	450
Lower repurchases of common shares under the NCIB in the current period compared to the same period in prior year.	66
Cash drawings under the syndicated credit facility.	57
Lower distributions paid to non-controlling interests due to lower net earnings in the current period.	22
Other	(25)
Cash flow used in financing activities for the six months ended June 30, 2025	**(77)**

Other Consolidated Analysis

Commitments

The Company has not incurred any additional material contractual commitments in the six months ended June 30, 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 during the six months ended June 30, 2025.

For the approximate future payments under the long-term service agreements as at June 30, 2025, refer to Note 18 in the unaudited interim condensed consolidated financial statements as at and for the six months ended June 30, 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 six months ended June 30, 2025.

Financial Instruments

For details on 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 six months ended June 30, 2025.

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 June 30, 2025, Level III instruments had a net liabilities carrying value of $255 million (Dec. 31, 2024 – net liabilities $234 million). The Level III liabilities increased during the six months ended June 30, 2025 from Dec. 31, 2024 due to unfavourable changes in market pricing across multiple markets driven by higher volatility, partially offset by 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 decrease 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.
- We adjust for the items included in the cash flow from operating activities related to the decision in 2020 to accelerate being off-coal and the shutdown of the Highvale mine in 2021 (Clean energy transition provisions and adjustments).
- 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 Assets 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
- Realized foreign exchange gain (loss)
- Unrealized foreign exchange gain (loss)
- The Alberta electricity portfolio metrics
- Realized merchant power price per MWh
- Hedged power price average per MWh
- 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 June 30, 2025:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	129	59	204	73	38	(67)	436	(3)	—	433
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	18	68	71	15	(2)	—	170	—	(170)	—
Decrease in finance lease receivable	—	—	7	—	—	—	7	—	(7)	—
Finance lease income	—	2	3	—	—	—	5	—	(5)	—
Revenues from Planned Divestitures	—	—	(3)	—	—	—	(3)	—	3	—
Unrealized foreign exchange gain on commodity	—	—	—	—	(2)	—	(2)	—	2	—
Adjusted revenue	147	129	282	88	34	(67)	613	(3)	(177)	433
Fuel and purchased power	7	9	106	51	—	—	173	—	—	173
Reclassifications and adjustments:										
Fuel and purchased power related to Planned Divestitures	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	7	9	105	51	—	—	172	—	1	173
Carbon compliance costs (recovery)	—	1	(8)	—	—	(67)	(74)	—	—	(74)
Adjusted gross margin	140	119	185	37	34	—	515	(3)	(178)	334
OM&A	13	25	65	18	8	45	174	(1)	—	173
Reclassifications and adjustments:										
OM&A related to Planned Divestitures	—	—	(1)	—	—	—	(1)	—	1	—
ERP integration costs	—	—	—	—	—	(6)	(6)	—	6	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(1)	(1)	—	1	—
Adjusted OM&A	13	25	64	18	8	38	166	(1)	8	173
Taxes, other than income taxes	1	5	5	—	—	1	12	—	—	12
Net other operating income	—	—	(12)	—	—	—	(12)	—	—	(12)
Adjusted EBITDA[2]	126	89	128	19	26	(39)	349			
Depreciation and amortization	(8)	(52)	(74)	(13)	—	(4)	(151)	1	—	(150)
Equity income	—	—	—	—	—	—	—	—	1	1
Interest income	—	—	—	—	—	7	7	(1)	—	6
Interest expense	—	—	—	—	—	(89)	(89)	1	—	(88)
Realized foreign exchange gain	—	—	—	—	—	6	6	—	—	6
Adjusted earnings (loss) before income taxes[2]	118	37	54	6	26	(119)	122			
Reclassifications and adjustments above	(18)	(70)	(80)	(15)	4	(7)	(186)			
Finance lease income	—	2	3	—	—	—	5	—	—	5
Skookumchuk earnings reclass to Equity income[1]	—	(1)	—	—	—	1	—	—	—	—
Asset impairment charges	—	—	—	(11)	—	(2)	(13)	—	—	(13)
Unrealized foreign exchange loss	—	—	—	—	—	(23)	(23)	—	—	(23)
Earnings (loss) before income taxes	100	(32)	(23)	(20)	30	(150)	(95)	—	—	(95)

(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.

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 June 30, 2024:

	Hydro	Wind & Solar(1)	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments(1)	Reclass adjustments	IFRS financials
Revenues	99	112	284	79	47	(34)	587	(5)	—	582
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	1	8	10	(14)	1	—	6	—	(6)	—
Decrease in finance lease receivable	—	—	5	—	—	—	5	—	(5)	—
Finance lease income	—	2	2	—	—	—	4	—	(4)	—
Unrealized foreign exchange gain on commodity	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted revenue	100	122	300	65	48	(34)	601	(5)	(14)	582
Fuel and purchased power	3	8	97	46	—	—	154	—	—	154
Carbon compliance costs (recovery)	—	—	26	—	—	(34)	(8)	—	—	(8)
Adjusted gross margin	97	114	177	19	48	—	455	(5)	(14)	436
OM&A	13	24	42	15	9	42	145	(1)	—	144
Reclassifications and adjustments:										
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(4)	(4)	—	4	—
Adjusted OM&A	13	24	42	15	9	38	141	(1)	4	144
Taxes, other than income taxes	1	4	3	2	—	—	10	(1)	—	9
Net other operating income	—	(2)	(10)	—	—	—	(12)	—	—	(12)
Adjusted EBITDA(2)(3)	83	88	142	2	39	(38)	316	—	—	—
Depreciation and amortization	(8)	(47)	(56)	(15)	(1)	(5)	(132)	1	—	(131)
Equity income	—	—	—	—	—	1	1	—	2	3
Interest income	—	—	—	—	—	8	8	—	—	8
Interest expense	—	—	—	—	—	(80)	(80)	—	—	(80)
Realized foreign exchange loss(3)	—	—	—	—	—	(1)	(1)	—	—	(1)
Adjusted earnings (loss) before income taxes(2)	75	41	86	(13)	38	(115)	112	—	—	—
Reclassifications and adjustments above	(1)	(10)	(16)	14	(1)	(4)	(18)	—	—	—
Finance lease income	—	2	2	—	—	—	4	—	—	4
Skookumchuk earnings reclass to Equity income(1)	—	(2)	—	—	—	2	—	—	—	—
Asset impairment (charges) reversals	—	(1)	—	1	—	(5)	(5)	—	—	(5)
Gain on sale of assets and other(3)	—	—	—	1	—	—	1	—	—	1
Unrealized foreign exchange loss(3)	—	—	—	—	—	(1)	(1)	—	—	(1)
Earnings (loss) before income taxes	74	30	72	3	37	(122)	94	—	—	94

(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.

(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. Therefore, the Company has applied this composition to all previously reported periods.

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 six months ended June 30, 2025:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	215	166	594	227	65	(66)	1,201	(10)	—	1,191
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(3)	104	39	14	(1)	—	153	—	(153)	—
Decrease in finance lease receivable	—	1	14	—	—	—	15	—	(15)	—
Finance lease income	—	3	8	—	—	—	11	—	(11)	—
Revenues from Planned Divestitures	—	—	(7)	—	—	—	(7)	—	7	—
Unrealized foreign exchange gain on commodity	—	—	—	—	(2)	—	(2)	—	2	—
Adjusted revenue	212	274	648	241	62	(66)	1,371	(10)	(170)	1,191
Fuel and purchased power	11	19	269	149	—	2	450	—	—	450
Reclassifications and adjustments:										
Fuel and purchased power related to Planned Divestitures	—	—	(3)	—	—	—	(3)	—	3	—
Adjusted fuel and purchased power	11	19	266	149	—	2	447	—	3	450
Carbon compliance costs (recovery)	—	2	41	—	—	(68)	(25)	—	—	(25)
Adjusted gross margin	201	253	341	92	62	—	949	(10)	(173)	766
OM&A	26	54	124	35	15	94	348	(2)	—	346
Reclassifications and adjustments:										
OM&A related to Planned Divestitures	—	—	(3)	—	—	—	(3)	—	3	—
ERP integration costs	—	—	—	—	—	(10)	(10)	—	10	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(5)	(5)	—	5	—
Adjusted OM&A	26	54	121	35	15	79	330	(2)	18	346
Taxes, other than income taxes	2	10	10	1	—	1	24	—	—	24
Net other operating income	—	(4)	(22)	—	—	—	(26)	—	—	(26)
Reclassifications and adjustments:										
Insurance recovery	—	2	—	—	—	—	2	—	(2)	—
Adjusted net other operating income	—	(2)	(22)	—	—	—	(24)	—	(2)	(26)
Adjusted EBITDA[2]	173	191	232	56	47	(80)	619			
Depreciation and amortization	(17)	(105)	(138)	(28)	(2)	(9)	(299)	3	—	(296)
Equity income	—	—	—	—	—	(1)	(1)	—	4	3
Interest income	—	—	—	—	—	12	12	(1)	—	11
Interest expense	—	—	—	—	—	(183)	(183)	2	—	(181)
Realized foreign exchange gain	—	—	—	—	—	2	2	—	—	2
Adjusted earnings (loss) before income taxes[2]	156	86	94	28	45	(259)	150			
Reclassifications and adjustments above	3	(106)	(60)	(14)	3	(15)	(189)			
Finance lease income	—	3	8	—	—	—	11	—	—	11
Skookumchuk earnings reclass to Equity income[1]	—	(4)	—	—	—	4	—	—	—	—
Fair value change in contingent consideration payable	—	—	34	—	—	—	34	—	—	34
Asset impairment (charges) reversals	—	—	(34)	13	—	(7)	(28)	—	—	(28)
Loss on sale of assets and other	—	—	—	—	—	(1)	(1)	—	—	(1)
Unrealized foreign exchange loss	—	—	—	—	—	(23)	(23)	—	—	(23)
Earnings (loss) before income taxes	159	(21)	42	27	48	(301)	(46)	—	—	(46)

(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 six months ended June 30, 2024:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	211	251	717	296	99	(34)	1,540	(11)	—	1,529
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(4)	(13)	(81)	(20)	(2)	—	(120)	—	120	—
Decrease in finance lease receivable	—	1	9	—	—	—	10	—	(10)	—
Finance lease income	—	3	3	—	—	—	6	—	(6)	—
Unrealized foreign exchange gain on commodity	—	—	(2)	—	—	—	(2)	—	2	—
Adjusted revenue	207	242	646	276	97	(34)	1,434	(11)	106	1,529
Fuel and purchased power	9	17	239	212	—	—	477	—	—	477
Carbon compliance costs (recovery)	—	—	66	—	—	(34)	32	—	—	32
Adjusted gross margin	198	225	341	64	97	—	925	(11)	106	1,020
OM&A	26	44	88	33	19	70	280	(2)	—	278
Reclassifications and adjustments:										
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(7)	(7)	—	7	—
Adjusted OM&A	26	44	88	33	19	63	273	(2)	7	278
Taxes, other than income taxes	2	8	6	2	—	—	18	(1)	—	17
Net other operating income	—	(4)	(20)	—	—	—	(24)	—	—	(24)
Adjusted EBITDA[2][3]	170	177	267	29	78	(63)	658			
Depreciation and amortization	(15)	(90)	(111)	(31)	(2)	(9)	(258)	3	—	(255)
Equity income	—	—	—	—	—	(1)	(1)	—	5	4
Interest income	—	—	—	—	—	15	15	—	—	15
Interest expense	—	—	—	—	—	(149)	(149)	—	—	(149)
Realized foreign exchange loss[4]	—	—	—	—	—	(9)	(9)	—	—	(9)
Adjusted earnings (loss) before income taxes[2]	155	87	156	(2)	76	(216)	256			
Reclassifications and adjustments above	4	9	71	20	2	(7)	99			
Finance lease income	—	3	3	—	—	—	6	—	—	6
Skookumchuk earnings reclass to Equity income[1]	—	(5)	—	—	—	5	—	—	—	—
Asset impairment (charges) reversals	—	(5)	—	4	—	(5)	(6)	—	—	(6)
Gain on sale of assets and other[4]	—	—	—	1	—	2	3	—	—	3
Unrealized foreign exchange gain[4]	—	—	—	—	—	3	3	—	—	3
Earnings (loss) before income taxes	159	89	230	23	78	(218)	361	—	—	361

(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.

(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. Therefore, the Company has applied this composition to all previously reported periods.

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

The following table reflects reconciliation of (loss) earnings before income taxes to adjusted net earnings attributable to common shareholders for the three and six months ended June 30, 2025 and June 30, 2024:

	3 months ended June 30		6 months ended June 30	
(in millions of Canadian dollars except where noted)	**2025**	**2024**	**2025**	**2024**
(Loss) earnings before income taxes	**(95)**	94	**(46)**	361
Income tax expense	**11**	28	**18**	57
Net (loss) earnings	**(106)**	66	**(64)**	304
Net (loss) earnings attributable to non-controlling interests	**(7)**	(3)	**(11)**	13
Preferred share dividends	**13**	13	**13**	13
Net (loss) earnings attributable to common shareholders	**(112)**	56	**(66)**	278
Adjustments and reclassifications (pre-tax):				
Adjustments and reclassifications to Revenues	**177**	14	**170**	(106)
Adjustments and reclassifications to Fuel and purchased power	**1**	—	**3**	—
Adjustments and reclassifications to OM&A	**8**	4	**18**	7
Adjustments and reclassifications to Net other operating income	**—**	—	**(2)**	—
Fair value change in contingent consideration payable (gain)	**—**	—	**(34)**	—
Finance lease income	**(5)**	(4)	**(11)**	(6)
Asset impairment charges	**13**	5	**28**	6
Loss (gain) on sale of assets and other	**—**	(1)	**1**	(3)
Unrealized foreign exchange loss (gain)[1]	**23**	—	**23**	(3)
Calculated tax (expense) recovery on adjustments and reclassifications[2]	**(51)**	(4)	**(46)**	24
Adjusted net earnings attributable to common shareholders[3]	**54**	70	**84**	197
Weighted average number of common shares outstanding in the period	**297**	303	**297**	306
Net (loss) income per common share attributable to common shareholders	**(0.38)**	0.18	**(0.22)**	0.91
Adjustments and reclassifications (net of tax)	**0.56**	0.05	**0.50**	(0.26)
Adjusted net earnings per common share attributable to common shareholders[3]	**0.18**	0.23	**0.28**	0.64

(1) Unrealized foreign exchange (loss) gain is a supplementary financial measure. Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A for more details.

(2) Represents a theoretical tax calculated by applying the Company's consolidated effective tax rate of 23.3 per cent for the three and six months ended June 30, 2025 (three and six months ended June 30, 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.

(3) 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 June 30		6 months ended June 30	
(in millions of Canadian dollars except where noted)	**2025**	**2024**	**2025**	**2024**
Cash flow from operating activities[1]	**157**	108	**164**	352
Change in non-cash operating working capital balances	**81**	114	**198**	107
Cash flow from operations before changes in working capital	**238**	222	**362**	459
Adjustments				
Share of adjusted FFO from joint venture[1]	**1**	2	**3**	4
Decrease in finance lease receivable	**7**	5	**15**	10
Clean energy transition provisions and adjustments	**—**	2	**—**	2
Brazeau penalties payment	**—**	—	**33**	—
Acquisition-related transaction and restructuring costs	**2**	4	**8**	7
Other[2]	**4**	1	**10**	8
FFO[3]	**252**	236	**431**	490
Deduct:				
Sustaining capital expenditures[1]	**(57)**	(40)	**(80)**	(40)
Dividends paid on preferred shares	**(13)**	(13)	**(26)**	(26)
Distributions paid to subsidiaries' non-controlling interests	**(2)**	(5)	**(2)**	(24)
Principal payments on lease liabilities	**—**	(1)	**(1)**	(2)
Other	**(3)**	—	**(6)**	—
FCF[3]	**177**	177	**316**	398
Weighted average number of common shares outstanding in the period	**297**	303	**297**	306
Cash flow from operating activities per share	**0.53**	0.36	**0.55**	1.15
FFO per share[3]	**0.85**	0.78	**1.45**	1.60
FCF per share[3]	**0.60**	0.58	**1.06**	1.30

(1) Includes our share of amounts for the Skookumchuck wind facility, an equity-accounted joint venture. Supplementary financial measure. Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A for more details.

(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. 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 June 30		6 months ended June 30	
	2025	**2024**	**2025**	**2024**
Adjusted EBITDA(1)(5)	**349**	316	**619**	658
Provisions	**(2)**	6	**6**	6
Net interest expense(2)	**(66)**	(57)	**(138)**	(105)
Current income tax expense	**(46)**	(33)	**(59)**	(60)
Realized foreign exchange gain (loss)(3)	**4**	(1)	**2**	(9)
Decommissioning and restoration costs settled	**(11)**	(12)	**(20)**	(19)
Other non-cash items	**24**	17	**21**	19
FFO(4)(5)	**252**	236	**431**	490
Deduct:				
Sustaining capital expenditures(3)(5)	**(57)**	(40)	**(80)**	(40)
Dividends paid on preferred shares	**(13)**	(13)	**(26)**	(26)
Distributions paid to subsidiaries' non-controlling interests	**(2)**	(5)	**(2)**	(24)
Principal payments on lease liabilities	**—**	(1)	**(1)**	(2)
Other	**(3)**	—	**(6)**	—
FCF(4)(5)	**177**	177	**316**	398

(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. 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) Supplementary financial measure. Refer to the Additional Non-IFRS and Supplementary Financial Measures section of this MD&A for more details.

(4) 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.

(5) 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 June 30		6 months ended June 30	
	2025	**2024**	**2025**	**2024**
Interest expense	**88**	80	**181**	149
Less: Interest Income	**(6)**	(8)	**(11)**	(15)
Less: non-cash items(1)	**(16)**	(15)	**(32)**	(29)
Net Interest Expense	**66**	57	**138**	105

(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	June 30, 2025	Dec. 31, 2024
Credit facilities, long-term debt and lease liabilities(1)	**3,761**	3,808
Exchangeable debentures	**350**	350
Less: Cash and cash equivalents	**(222)**	(337)
Add: Bank overdraft	**—**	1
Add: 50 per cent of issued preferred shares and exchangeable preferred shares(2)	**671**	671
Other(3)	**2**	(24)
Adjusted net debt(4)	**4,562**	4,469
Adjusted EBITDA(5)	**1,216**	1,255
Adjusted net debt to adjusted EBITDA (times)	**3.8**	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 June 30, 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 June 30, 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 operating and investing activities and lower annualized adjusted EBITDA as at June 30, 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)(4)]	$1,150 to $1,250 million	$1,255 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 and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the Reconciliation of Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. See also the Additional 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.

(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.

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)	$50 to $70
AECO gas price ($/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	Q3 2025	Q4 2025	Full Year 2025	Full Year 2026
Hedged production (GWh)	2,394	1,891	8,532	6,957
Hedge price ($/MWh)	$67	$71	$70	$67
Hedged gas volumes (GJ)	13 Million	8 Million	43 Million	23 Million
Hedge gas prices ($/GJ)	$2.80	$3.54	$3.02	$3.53

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 June 30, 2025, we had access to $1.5 billion in liquidity, including $222 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 six months ended June 30, 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

The Trump Administration has issued numerous executive orders imposing tariffs on Canada, Mexico and China, reciprocal tariffs on over 60 countries and product-specific tariffs including automobiles, steel and aluminum. Many of these tariffs have been paused while tariffs are being negotiated. 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. The 25 per cent tariffs on Canadian goods and 10 per cent for energy exports do not include electricity. On June 27, 2025, President Trump said the U.S. is immediately ending trade talks with Canada in response to Canada's Digital Services Tax (DST) on technology companies. On June 30, 2025, the Canadian government stated that it would rescind the DST in anticipation of a mutually beneficial comprehensive trade arrangement with the U.S. On July 10, 2025, President Trump threatened increasing the Canadian tariffs to 35 per cent, effective Aug. 1, 2025, with potential carve-outs for certain goods at lower rates. 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. Refer to the Regulatory Updates section of this MD&A for more details.

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 7 and IFRS 9 — 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 and such impacts cannot be reasonably estimated at this time.

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 and such impacts cannot be reasonably estimated at this time.

IFRS 18 — Presentation and Disclosure in Financial Statements

On Apr. 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 and such impacts cannot be reasonably estimated at this time.

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 continues to monitor policy developments related to our business, including but not limited to the Clean Electricity Regulations, Investment Tax Credits, industrial carbon pricing, as well as funding for net-zero technologies.

On April 23, 2025, the Canadian Securities Administrators announced the pause on the development of their new mandatory rule National Instrument 51-107 Disclosure of Climate-related Matters. This decision was taken to support Canadian markets and issuers as they adapt to the recent developments in the U.S. and globally. TransAlta continues to monitor this development.

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 second quarter, the AESO proposed an updated Restructured Energy Market (REM) design to address concerns regarding the complexity, scale and timeline.

On May 22, 2025, the AESO issued its updated high-level REM design paper, which proposed the following key elements for the REM design: (1) staged in increases to the energy market offer cap from $999.99/MWh to $1,500/MWh in 2027 and then to $2,000/MWh in 2032, as well as the introduction of negative pricing to -$100/MWh in 2032; (2) a new real-time 30-minute ramping product; (3) a secondary offer cap mechanism that would cap offers of dispatchable thermal resources at $400/MWh for market participants with offer control of five per cent or greater when triggered along with a local market power mechanism; and (4) the replacement of the interim Supply Cushion Regulation long lead time asset directive mechanism with a reliability unit commitment process.

The AESO plans to continue engaging with industry stakeholders over the remainder of 2025 and into the first quarter of 2026 to finalize the high-level REM design and to develop the REM market rules. TransAlta continues to assess the proposed design changes and participate in the AESO consultation process. At this time, the AESO plans to work on information technology system development work over 2026 and 2027 with the intent to implement REM in 2027 or 2028.

On June 4, 2025, the AESO advised that 1,200 MW of large load hosting capacity will be made available for Phase I data centre development with in-service dates in 2027-28, as well as details regarding the process it will engage in over the next two months to award that capacity to the eligible project proponents. In tandem, the Government of Alberta and AESO are proceeding with the design the requirements for Phase II of data centre developments; this will apply to data centre projects that have in-service dates in beyond 2028. Finalization of the Phase II design is expected to occur by fall 2025. TransAlta is actively engaged with the AESO and stakeholders on large load connection and data centre development in the province.

United States

During the three and six months ended June 30, 2025, the President of the United States has signed a number of executive orders seeking to enable gas and coal-fired generation 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. During the three months ended June 30, 2025, pursuant to this authority, citing reliability concerns, the U.S. Department of

Energy (U.S. DOE) issued emergency orders requiring fossil plants in two states to stay online and the U.S. Environmental Protection Agency has provided numerous coal facilities 2-year exemptions from certain Clean Air Act requirements. On July 7, 2025, the U.S. DOE issued a resource adequacy framework for all U.S. regions that may serve as the basis for future emergency orders. The net effect of these actions may lead to existing power plants staying online past planned retirement dates; moreover, they may impact demand for new generation sources and could also 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.

The Trump Administration has issued numerous Executive Orders imposing tariffs on Canada, Mexico and China, reciprocal tariffs on over 60 countries and product-specific tariffs including on automobiles, steel and aluminum. Many of these tariffs have been paused while tariffs are being negotiated. The 25 per cent tariffs on Canadian goods and 10 per cent for energy exports do not include electricity at this time.

On July 4, 2025 President Trump signed into law a budget reconciliation bill, the *"One Big Beautiful Bill" Act* (Bill), which significantly reduced the availability of federal tax credits for renewable technologies established under the Inflation Reduction Act (IRA) of 2022. IRA tax credits for wind and solar were substantially rolled back as part of the Bill. The Bill retained the 100 per cent value tax credits for wind and solar through 2027, provided that the projects are placed in service by Dec. 31, 2027. An exception applies for wind and solar projects that start construction by July 3, 2026 and complete construction by 2030. By mid-August 2025, the Internal Revenue Service will be reviewing and potentially providing new investment tax credit and production tax credit guidance for wind and solar, including start of construction rules. The Bill introduces supply chain limitations on project components from foreign entities of concern. The Bill retains the IRA's favourable transferability provisions, preserving the ability to sell or transfer credits for the full duration of the credit. Additionally, the Bill provides favourable treatment for energy storage with full tax credits available for projects starting construction before 2033.

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 Labor 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 and six months ended June 30, 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 as at June 30, 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 19 per cent of the Company's total and net assets, respectively, as at June 30, 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 June 30, 2025, the end of the period covered by this MD&A, our ICFR and DC&P were effective.

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 and consist 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, Keephills, Battle River and Sheerness facilities 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) less 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 facilities (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 and original maturity on Sept. 7, 2025, bearing floating interest rates that varied depending on the option selected (e.g., Canadian prime and bankers' acceptances). On March 25, 2025, the Company repaid the term facility in advance of the scheduled maturity date with the proceeds received from the $450 million senior notes offering.

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.