TRANSALTA CORPORATION Management's Discussion and Analysis

Third Quarter Report for 2024

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 nine months ended Sept. 30, 2024 and 2023, and should be read in conjunction with the audited annual consolidated financial statements and MD&A ("2023 Annual MD&A") contained within our 2023 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 Sept. 30, 2024. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted, except amounts per share, which are in whole dollars to the nearest two decimals. This MD&A is dated Nov. 4, 2024. Additional information respecting TransAlta, including our Annual Information Form ("AIF") for the year ended Dec. 31, 2023, 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 United States securities laws, including the *Private Securities Litigation Reform Act* of 1995 (collectively referred to herein as "forward-looking statements"). All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumption was made and on management's experience and perception of historical trends, current conditions and expected future developments, as well as other factors deemed appropriate in the circumstances. 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 including, but not limited to, statements relating to: the Company's ability to deliver its 2024 Outlook, including Adjusted EBITDA, free cash flow, annualized dividends per share, sustaining capital spending, energy marketing gross margin, corporate cash taxes and cash interest; the Company's growth targets to deliver 1.75 GW with a target investment of $3.5 billion by 2028 that will deliver annual EBITDA of $350 million; the expansion of the Company's development pipeline to 10 GW by 2028; the temporary mothballing of Sundance 6 and its return to service; our acquisition of Heartland; the Company's Mount Keith West Network Upgrade project currently under construction, including as it pertains to capital costs, the timing of commercial operation and expected annual EBITDA; the development of early-stage and advanced-stage projects; the expected annual average EBITDA to be generated from the transfer of PTCs (defined below) generated from the White Rock and Horizon Hill wind projects; the Company's hedging strategy and the ability of such strategy to provide greater cash flow certainty; the delivery of stable and predictable cash flows; the proportion of EBITDA to be generated from renewable sources to increase to 70 per cent by the end of 2028; Our plans to cease coal generation at the end of 2025; regulatory developments and their expected impact on the Company; the effect of the implementation of the Alberta "Restructured Energy Market" and the Company's expectations that the near-term impacts of the announced Alberta regulatory changes on the Company's existing assets will be muted; the characteristics of the "Restructured Energy Market", including that it will provide a scarcity pricing mechanism; the pause on new growth projects in Alberta until the new market structure is defined; the seasonality of the business, including that higher maintenance costs are often incurred in the spring and fall when electricity prices are expected to be lower; the Company's common share repurchase program for 2024 of up to $150 million, and returning to shareholders in the form of share repurchases and dividends up to 42 per cent of the Company's 2024 free cash guidance.

The forward-looking statements contained in this MD&A are based on many assumptions including, but not limited to, the following: the power and natural gas price assumptions contained within the 2024 Outlook; no significant changes to applicable laws and regulations beyond those that have already been announced; no significant changes to fuel and purchased power costs; no material adverse impacts to long-term investment and credit markets; no significant changes to power price and hedging assumptions, including hedged volumes and prices; no significant changes to gas commodity prices and transport costs; no significant changes to decommissioning and restoration costs; no significant changes to interest rates; no significant changes to the demand and growth of renewables generation; no significant changes to the integrity and reliability of our assets; planned and unplanned outages; and no significant changes to the Company's debt and credit ratings.

Forward-looking statements are subject to a number of significant risks and uncertainties that could cause actual plans, performance, results or outcomes to differ materially from current expectations. Factors that may adversely impact what is expressed or implied by forward-looking statements contained in this MD&A include risks relating to: fluctuations in power prices, including merchant pricing in Alberta, Ontario and Mid-Columbia; failure or delay in closing the Heartland acquisition; failure to realize the benefits of the Heartland acquisition, and any loss of value in the Heartland portfolio during the interim period prior to closing; reductions in production; restricted access to capital and increased borrowing costs, including any difficulty raising debt, equity or tax equity, as applicable, on reasonable terms or at all; labour relations matters, reduced labour availability and the ability to continue to staff our operations and facilities; reliance on key personnel; disruptions to our supply chains, including our ability to secure necessary equipment; force majeure claims; our ability to obtain regulatory and any other third-party approvals on the expected timelines or at all in respect of our growth projects; long-term commitments on gas transportation capacity that may not be fully utilized over time; adverse financial impacts arising from the Company's hedged position; risks associated with development and construction projects, including increased capital costs, permitting challenges, labour and engineering risks, disputes with contractors and potential delays in the construction or commissioning of such projects; significant fluctuations in the Canadian dollar against the US dollar and Australian dollar; changes in short-term and long-term electricity supply and demand; counterparty risks, including risk of nonperformance and higher rates of losses on our accounts receivables; inability to achieve our environmental, social and governance ("ESG") targets and impacts arising from changes in ESG requirements; the impact of the energy transition on our business; impairments and/or writedowns of assets; adverse impacts on our information technology systems and our internal control systems, including cybersecurity threats; commodity risk management and energy trading risks, including the effectiveness of the Company's risk management tools associated with hedging and trading procedures to protect against significant losses; our ability to contract our generation for prices that will provide expected returns and to replace or extend contracts as they expire; changes to the legislative, regulatory and political environments in the jurisdictions in which we operate, including the impacts in Alberta relating to restrictions on renewable energy projects, amended Alberta Electric System Operator ("AESO") rules relating to the Supply Cushion Regulation and Market Power Mitigation Regulation, expected changes to Transmission Regulations, and the creation of the Restructured Energy Market; environmental requirements and changes in, or liabilities under, these requirements; disruptions in the transmission and distribution of electricity; the effects of weather, including man-made or natural disasters and other climate-change related risks; increases in costs; reductions to our generating units' relative efficiency or capacity factors; disruptions in the source of fuels, including natural gas, coal, water, solar or wind resources required to operate our facilities; operational risks, unplanned outages and equipment failure and our ability to carry out or have completed any repairs in a cost-effective or timely manner or at all; failure to meet financial expectations; general domestic, international economic and political developments, including armed hostilities, the threat of terrorism, adverse diplomatic developments or other similar events; industry risk and competition in the business in which we operate; structural subordination of securities; public health crisis risks; inadequacy or unavailability of insurance coverage; our provision for income taxes and any risk of reassessment; and legal, regulatory and contractual disputes and proceedings involving the Company. 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, 2023.

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 is a Canadian corporation and one of Canada's largest publicly traded power generators. Established in 1911, the Company has over 113 years of experience in the development and operation of electricity generation. We own, operate and manage a geographically diversified portfolio of generation assets that includes water, wind, solar, battery storage, natural gas and coal. TransAlta will cease coal-fired generation at the end of 2025. We are one of the largest producers of wind power and thermal generation in Canada and the largest producer of hydro power in Alberta. We also have industry-leading energy marketing capabilities where we seek to maximize margins by securing and optimizing high-value products and markets for ourselves and our customers in dynamic market conditions. Our mix of merchant and contracted assets along with our energy marketing business provide resilient cash flows that support our ability to maintain our balance sheet, return capital to our shareholders and reinvest in growth.

Portfolio of Assets

Our asset portfolio is geographically diversified with operations across Canada, the United States and Australia.

Our Hydro, Wind and Solar, Gas and Energy Transition segments are responsible for operating and maintaining our electrical 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 of gas, transport and storage for our gas fleet, providing expertise and 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 high-quality contracted assets and merchant assets. Our merchant assets include our unique hydro merchant portfolio and our merchant legacy thermal portfolio and wind assets. Our merchant exposure is primarily in Alberta, where 49 per cent of our capacity is located and 76 per cent of which is available to participate in the merchant electricity market.

The Company deploys hedging strategies which include maintaining a significant base of commercial and industrial ("C&I") customers, supplemented with financial hedges. A significant portion of our thermal generation capacity in Alberta is hedged to provide greater cash flow certainty while capturing higher risk-adjusted returns for our shareholders. Refer to the 2024 Outlook and the Optimization of the Alberta Portfolio sections of this MD&A for further details.

On Jan. 1, 2024, the 100 MW White Rock West wind facility achieved commercial operation and on Feb. 29, 2024, the Mount Keith 132kV expansion project was completed. The 200 MW White Rock East and the 200 MW Horizon Hill wind facilities achieved commercial operation on April 22, 2024 and May 21, 2024, respectively, increasing the Company's fully contracted renewables fleet in the United States to over 1,000 MW.

The following table provides our consolidated ownership of our facilities across the regions in which we operate as of Sept. 30, 2024:

	Hydro		Wind & Solar		Gas		Energy Transition		Total	
As at Sept. 30, 2024	Gross Installed Capacity (MW)	Number of facilities	Gross Installed Capacity (MW)(1)	Number of facilities	Gross Installed Capacity (MW)(1)	Number of facilities	Gross Installed Capacity (MW)	Number of facilities(2)	Gross Installed Capacity (MW)(1)	Number of facilities
Alberta	834	17	766	14	1,963	7	—	—	3,563	38
Canada, excluding Alberta	88	7	751	9	645	3	—	—	1,484	19
US	—	—	1,019	10	29	1	671	2	1,719	13
Australia	—	—	48	3	450	6	—	—	498	9
Total	**922**	**24**	**2,584**	**36**	**3,087**	**17**	**671**	**2**	**7,264**	**79**

(1) Gross installed capacity for consolidated reporting represents 100 per cent of the capacity of a facility. Capacity figures for the Wind and Solar segment include 100 per cent of the Kent Hills wind facilities, and capacity figures for the Gas segment include 100 per cent of the Ottawa and Windsor facilities, 50 per cent of the Sheerness facility and 60 per cent of the Fort Saskatchewan facility.

(2) Includes Centralia coal facility and the Skookumchuck hydro facility.

Contracted Capacity

The following table provides our contracted capacity by MW and as a percentage of total gross installed capacity of our facilities across the regions in which we operate as of Sept. 30, 2024:

As at Sept. 30, 2024	Hydro	Wind & Solar	Gas	Energy Transition	Total
Alberta	—	336	511	—	847
Canada, excluding Alberta	88	751	645	—	1,484
US	—	1,019	29	381	1,429
Australia	—	48	450	—	498
Total contracted capacity (MW)	88	2,154	1,635	381	4,258
Contracted capacity as a % of total capacity (%)	10%	83%	53%	57%	59%

Approximately 59 per cent of our total installed capacity is contracted with investment-grade or creditworthy counterparties.

The following table provides the weighted average contract life of our contracted and merchant facilities across the regions in which we operate as of Sept. 30, 2024:

As at Sept. 30, 2024	Hydro	Wind & Solar	Gas	Energy Transition	Total
Alberta	—	8	2	—	3
Canada, excluding Alberta	10	9	7	—	9
US	—	13	1	1	8
Australia	—	14	14	—	14
Total weighted contract life (years)	1	10	5	1	6

Highlights

The Company has demonstrated strong financial and operational performance during the three and nine months ended Sept. 30, 2024, and is on track to achieve the upper end of its 2024 Outlook, due to active management of the Company's merchant portfolio and hedging strategies, along with the achievement of commercial operation of the White Rock and Horizon Hill wind facilities and the Northern Goldfields solar facilities. During the second and third quarters of 2024, the Company settled a higher volume of hedges at prices that were significantly above the spot market.

	3 months ended Sept. 30		9 months ended Sept. 30	
(in millions of Canadian dollars except where noted)	2024	2023	2024	2023
Operational information				
Adjusted availability (%)	**94.5**	91.9	**92.5**	89.4
Production (GWh)	**5,712**	5,678	**16,612**	16,246
Select financial information				
Revenues	**638**	1,017	**2,167**	2,731
Earnings before income taxes	**9**	453	**370**	915
Adjusted EBITDA[1]	**325**	453	**968**	1,343
Net earnings (loss) attributable to common shareholders	**(36)**	372	**242**	728
Cash flows				
Cash flow from operating activities	**229**	681	**581**	1,154
Funds from operations[1][2]	**200**	357	**673**	1,122
Free cash flow[1][2]	**140**	228	**521**	769
Per share				
Weighted average number of common shares outstanding	**296**	263	**303**	265
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.12)**	1.41	**0.80**	2.75
Funds from operations per share[1][2]	**0.68**	1.36	**2.22**	4.23
Free cash flow per share[1][2]	**0.47**	0.87	**1.72**	2.90

As at	Sept. 30, 2024	Dec. 31, 2023
Liquidity and capital resources		
Available liquidity	**1,774**	1,738
Adjusted net debt to adjusted EBITDA[1] (times)	**3.2**	2.5
Total consolidated net debt[1][3]	**3,349**	3,453
Assets and liabilities		
Total assets	**8,654**	8,659
Total long-term liabilities	**4,458**	5,253
Total liabilities	**6,733**	6,995

(1) These items are not defined and have no standardized meaning under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings (loss) trends more readily in comparison with prior periods' results. Refer to the Segmented Financial Performance and Operating Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. Also, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(2) Funds from operations ("FFO") per share and free cash flow ("FCF") per share are calculated using the weighted-average number of common shares outstanding during the period. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for the purpose of these non-IFRS ratios.

(3) Refer to the table in the Financial Capital section of this MD&A for more details on the composition of total consolidated net debt.

Operating Performance

Adjusted Availability

The following table provides adjusted availability by segment:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2024	**2023**	**2024**	**2023**
Hydro	**94.3**	97.8	**92.3**	95.6
Wind and Solar	**93.7**	87.0	**93.8**	85.7
Gas	**96.3**	94.6	**95.4**	92.3
Energy Transition	**90.0**	86.2	**76.1**	79.8
Adjusted availability (%)	**94.5**	91.9	**92.5**	89.4

Availability is an important measure for the Company as it represents the percentage of time a facility is available to produce electricity and is therefore an important indicator of the overall performance of the fleet.

Availability is impacted by planned and unplanned outages, and derates. The Company schedules dedicated time (planned outages) to maintain, repair or make improvements to the facilities with a view to minimizing the impact to operations. In high-price environments, actual outage schedules may change to accelerate the return to service of the unit.

Adjusted availability for the three and nine months ended Sept. 30, 2024, increased by 2.6 and 3.1 percentage points, respectively.

For the three and nine months ended Sept. 30, 2024, higher adjusted availability compared to the same periods in 2023, was primarily due to:

- The addition of the White Rock and Horizon Hill wind facilities and the Northern Goldfields solar facilities;
- The return to service of the Kent Hills wind facilities; and
- Lower planned and unplanned outages at Sheerness Unit 1 and Keephills Unit 3 and lower derates at Sundance Unit 6 in the Gas segment; partially offset by
- Higher planned major maintenance outages and unplanned outages in the Hydro segment.

The adjusted availability for the nine months ended Sept. 30, 2024, was further impacted by:

- Higher planned and unplanned outages during the first and second quarters of 2024 at Centralia Unit 2 in the Energy Transition segment.

Production and Long-Term Average Generation

	2024			2023		
3 months ended Sept. 30	**Actual production (GWh)**	**LTA generation (GWh)**	**Production as a % of LTA generation**	**Actual production (GWh)**	**LTA generation (GWh)**	**Production as a % of LTA generation**
Hydro	**494**	**573**	**86 %**	521	573	91%
Wind and Solar	**1,121**	**1,472**	**76 %**	708	1,246	57%
Gas	**3,119**			3,294		
Energy Transition	**978**			1,155		
Total	**5,712**			5,678		

	2024			2023		
9 months ended Sept. 30	**Actual production (GWh)**	**LTA generation (GWh)**	**Production as a % of LTA generation**	**Actual production (GWh)**	**LTA generation (GWh)**	**Production as a % of LTA generation**
Hydro	**1,271**	**1,568**	**81 %**	1,443	1,568	92%
Wind and Solar	**4,118**	**4,701**	**88 %**	2,764	3,766	73%
Gas	**9,442**			8,981		
Energy Transition	**1,781**			3,058		
Total	**16,612**			16,246		

In addition to adjusted availability, the Company utilizes long-term average production ("LTA generation") as another indicator of performance for the renewable assets whereby actual production levels are compared against the expected long-term average. In the short term, for each of the Hydro and Wind and Solar segments, the conditions will vary from one period to the next. Over longer durations, facilities are expected to produce inline with their long-term averages, which is 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 units are dispatchable and their production is largely dependent on market conditions and merchant demand.

Total production for the three and nine months ended Sept. 30, 2024, increased compared with the same periods in 2023.

Hydro production for the three and nine months ended Sept. 30, 2024, decreased by 27 GWh and 172 GWh, or five per cent and 12 per cent, respectively. Lower energy production at Hydro was due to:

- Lower water resources in the North Saskatchewan River region; and
- Increased planned outages across the fleet compared to the same period in 2023.

Wind and Solar production for the three and nine months ended Sept. 30, 2024, increased by 413 GWh and 1,354 GWh, or 58 per cent and 49 per cent, respectively, primarily due to:

- Production from new facilities, including the Northern Goldfields solar facilities commissioned in November 2023, the White Rock West and East wind facilities commissioned in January and April 2024, respectively, and the Horizon Hill facility commissioned in May 2024;
- The return to service of the Kent Hills wind facilities in the first quarter of 2024; and
- Precommissioning production from the White Rock East and the Horizon Hill wind facilities in the first quarter of 2024.

The increase in Wind and Solar production for the nine months ended Sept. 30, 2024, further benefited from production from the Garden Plain wind facility commissioned in August 2023.

Gas segment production for the three months ended Sept. 30, 2024, decreased by 175 GWh, or five per cent, primarily due to higher dispatch optimization in Alberta.

Gas segment production for the nine months ended Sept. 30, 2024, increased by 461 GWh, or five per cent. The higher production was primarily driven by favourable market conditions in the Ontario wholesale power market which enabled higher dispatch at the Sarnia facility that resulted in higher merchant production to the Ontario grid, partially offset by higher dispatch optimization in Alberta.

Production from the Energy Transition segment for the three and nine months ended Sept. 30, 2024, was negatively impacted by increased economic dispatch at the Centralia facility resulting from lower market prices compared to prior periods. The nine months ended Sept. 30, 2024, was further impacted by higher planned and unplanned outage hours in the first and second quarters of 2024.

Market Pricing

	3 months ended Sept. 30		9 months ended Sept. 30	
	2024	**2023**	**2024**	**2023**
Alberta spot power price ($/MWh)	**55**	152	**67**	151
Mid-Columbia spot power price (US$/MWh)	**50**	78	**61**	78
Ontario spot power price ($/MWh)	**34**	35	**32**	28
Natural gas price (AECO) ($/GJ)	**0.67**	2.49	**1.24**	2.65

For the three and nine months ended Sept. 30, 2024, spot electricity prices in Alberta were on average lower compared with the same periods in 2023, driven by additions of new natural gas, wind and solar supply and lower natural gas prices.

Spot electricity prices in the Pacific Northwest were lower on average compared to the same periods in 2023 due to lower natural gas prices.

AECO natural gas prices for the three and nine months ended Sept. 30, 2024, were lower compared with the same periods in 2023, mainly due to higher gas production and higher storage levels in Alberta and throughout North America.

Financial Performance review on Consolidated Information

	3 months ended Sept. 30		9 months ended Sept. 30	
	2024	**2023**	**2024**	**2023**
Revenues	**638**	1,017	**2,167**	2,731
Fuel and purchased power	**213**	269	**690**	782
Carbon compliance	**41**	28	**73**	85
Operations, maintenance and administration	**143**	131	**421**	389
Depreciation and amortization	**133**	140	**388**	489
Asset impairment charges (reversals)	**20**	(58)	**26**	(74)
Earnings before income taxes	**9**	453	**370**	915
Income tax expense	**31**	34	**88**	65
Net earnings (loss) attributable to common shareholders	**(36)**	372	**242**	728
Net earnings attributable to non-controlling interests	**1**	33	**14**	96

Third Quarter Variance Analysis (2024 versus 2023)

Revenues for the three and nine months ended Sept. 30, 2024, decreased by $379 million and $564 million, respectively, or 37 per cent and 21 per cent, respectively, compared to the same periods in 2023, broadly inline with expectations. The decrease was primarily due to:

- Lower merchant spot and hedged power prices in the Alberta market. The Company settled a higher volume of power hedges in the second and third quarters of 2024 that generated positive contributions over spot power prices;
- Lower revenue from derivatives and other trading activities in the Wind and Solar segment driven by higher unrealized mark-to-market losses on the new long-term wind energy sales related to the Oklahoma projects in Central US. The unrealized losses on the long-term Central US wind energy sales is due to the strengthening forecasted wind capture prices reflected in the period; partially offset by
- Commercial operation of the White Rock and Horizon Hill wind facilities and the Northern Goldfields solar facilities; and
- Higher environmental and tax attributes revenues from the Hydro segment and from the sale of production tax credits from the Oklahoma wind facilities to taxable US counterparties.

Revenues for the nine months ended Sept. 30, 2024, was further impacted by:

- Lower production at Centralia from higher economic dispatch due to lower market prices and higher planned and unplanned outage hours for scheduled maintenance in the first and second quarters of 2024.

Fuel and purchased power costs for the three and nine months ended Sept. 30, 2024, decreased by $56 million and $92 million, respectively, or 21 per cent and 12 per cent, respectively, compared to the same periods in 2023, primarily due to:

- Lower purchased power costs driven by lower Mid-C prices on repurchases of power and lower production;
- Higher dispatch optimization in the Alberta Gas and higher economic dispatch in the Energy Transition segments; and
- Lower natural gas prices; partially offset by
- Higher production in the Gas segment in the first and second quarters of 2024.

Carbon compliance costs for the three months ended Sept. 30, 2024, increased by $13 million, or 46 per cent, compared to the same period in 2023, primarily due to:

- An increase in the carbon price per tonne from $65 per tonne in 2023 to $80 per tonne in 2024; partially offset by
- Lower production in the Gas segment.

Carbon compliance costs for the nine months ended Sept. 30, 2024, decreased by $12 million, or 14 per cent, compared to the same period in 2023, primarily due to:

- The utilization of internally generated and externally purchased emission credits to settle a portion of our 2023 greenhouse gas ("GHG") obligation; partially offset by
- An increase in carbon price per tonne in 2024; and
- Higher production in the Gas segment.

Operations, maintenance and administration ("OM&A") expenses for the three and nine months ended Sept. 30, 2024, increased by $12 million and $32 million, respectively, or nine and eight per cent, respectively, compared to the same periods in 2023, primarily due to:

- The addition of the Garden Plain, White Rock and Horizon Hill wind facilities and the Northern Goldfields solar facilities, salary escalations and long-term service agreement escalations;
- Higher spending relating to planning and design work on a planned upgrade to the enterprise resource planning ("ERP") system; and
- Higher spending on strategic and growth initiatives, including higher legal costs.

Depreciation and amortization for the three and nine months ended Sept. 30, 2024, decreased by $7 million and $101 million, respectively, or five per cent and 21 per cent, respectively, compared to the same periods in 2023, primarily due to:

- Revisions to useful lives on certain facilities in prior periods; partially offset by
- Commercial operation of the White Rock and Horizon Hill wind facilities and return to service at Kent Hills.

Asset impairment charges for the three and nine months ended Sept. 30, 2024, increased by $78 million and $100 million, respectively, or 134 per cent and 135 per cent, respectively, compared to asset impairment recoveries in the same periods in 2023, primarily due to changes in decommissioning and restoration provisions related to discount rates and revisions in estimated costs to decommission retired assets.

Earnings before income taxes for the three and nine months ended Sept. 30, 2024, decreased by $444 million and $545 million, respectively, or 98 per cent and 60 per cent, compared to the same periods in 2023, 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 Sept. 30, 2024, decreased by $3 million, or nine per cent, compared to the same period in 2023, primarily due to:

- Lower earnings before income taxes due to the above noted items; partially offset by
- A recovery related to the reversal of previously derecognized Canadian deferred tax assets.

Income tax expense for the nine months ended Sept. 30, 2024, increased by $23 million, or 35 per cent, compared to the same period in 2023, primarily due to:

- A recovery related to the reversal of previously derecognized Canadian deferred tax assets; partially offset by
- Lower earnings before income taxes due to the above noted items.

Net (loss) earnings attributable to non-controlling interests for the three and nine months ended Sept. 30, 2024, decreased by $32 million and $82 million, respectively, or 97 per cent and 85 per cent, respectively, compared to the same periods in 2023, primarily due to lower net earnings for TransAlta Cogeneration, LP ("TA Cogen") resulting from lower merchant pricing in the Alberta market and the acquisition of TransAlta Renewables Inc. ("TransAlta Renewables") on Oct. 5, 2023.

Adjusted EBITDA

For the three and nine months ended Sept. 30, 2024, the Company's adjusted EBITDA was $325 million and $968 million, respectively, as compared to $453 million and $1,343 million, respectively, in 2023, a decrease of $128 million and $375 million, respectively. The major factors impacting adjusted EBITDA are summarized in the following tables:

	3 months ended Sept. 30
Adjusted EBITDA for the three months ended Sept. 30, 2023	453
Hydro: lower primarily due to lower power prices in the Alberta market and lower energy production, partially offset by higher ancillary service volumes due to increased demand by the AESO, realized premiums above spot power prices and higher sales of emission credits to third parties and intercompany sales to the Gas segment.	(61)
Wind and Solar: higher primarily due to new sales of production tax credits, the commercial operation of the White Rock and Horizon Hill wind facilities and the Northern Goldfields solar facilities and the return to service of the Kent Hills wind facilities, partially offset by lower realized power pricing in the Alberta market and higher OM&A due to the addition of the new wind and solar facilities.	7
Gas: lower primarily due to lower production due to increased dispatch optimization driven by lower power prices in Alberta and lower capacity payments, partially offset by higher volume of favourable hedging positions settled, lower natural gas prices and lower planned outages in Alberta.	(115)
Energy Transition: higher primarily due to lower purchased power costs, partially offset by increased economic dispatch due to lower market prices which negatively impacted production.	5
Energy Marketing: higher primarily due to favourable market volatility and timing of realized settled trades during the period in comparison to the prior period.	41
Corporate: lower primarily due to increased spending for planning and design of ERP upgrade program and to support strategic and growth initiatives.	(5)
Adjusted EBITDA[(2)] for the three months ended Sept. 30, 2024	**325**

(1) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

	9 months ended Sept. 30
Adjusted EBITDA for the nine months ended Sept. 30, 2023	1,343
Hydro: lower primarily due to lower power prices in the Alberta market and lower energy production, partially offset by higher ancillary service volumes due to increased demand by the AESO, realized premiums above spot power prices and higher sales of emission credits to third parties and intercompany sales to the Gas segment.	(144)
Wind and Solar: higher primarily due to new sales of production tax credits, the commercial operation of the White Rock and Horizon Hill wind facilities and the Northern Goldfields solar facilities and the return to service of the Kent Hills wind facilities, partially offset by lower realized power pricing in the Alberta market and higher OM&A due to the addition of the new wind and solar facilities.	46
Gas: lower primarily due to lower production due to increased dispatch optimization driven by lower realized power prices in Alberta, lower capacity payments and an increase in the carbon price, partially offset by higher volume of favourable hedging positions settled, higher production, lower planned outages in Alberta, lower natural gas prices and the utilization of emission credits in the second quarter of 2024 to settle a portion of our 2023 GHG obligation.	(241)
Energy Transition: lower primarily due to increased economic dispatch due to lower market prices which negatively impacted production, partially offset by lower fuel and purchased power costs.	(33)
Energy Marketing: higher primarily due to favourable market volatility and timing of realized settled trades during the period in comparison to the prior period.	9
Corporate: lower primarily due to increased spending for planning and design of ERP upgrade program and to support strategic and growth initiatives.	(12)
Adjusted EBITDA(1) for the nine months ended Sept. 30, 2024	**968**

(1) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Free Cash Flow

For the three and nine months ended Sept. 30, 2024, the Company's FCF decreased by $88 million and $248 million, respectively, or 39 per cent and 32 per cent, compared with the same periods in 2023. The major factors impacting FCF are summarized in the following table:

	3 months ended Sept. 30
FCF for the three months ended Sept. 30, 2023	228
Lower adjusted EBITDA due to the items noted above.	(128)
Higher current income tax expense due to the full utilization of Canadian non-capital loss carryforwards in 2023 offset by lower earnings before income taxes in the period.	(26)
Higher net interest expense[1] due to lower capitalized interest as a result of capital projects being completed in the first half of 2024 and lower interest income resulting from lower cash balances.	(22)
Lower distributions paid to subsidiaries' non-controlling interests relating to lower TA Cogen net earnings resulting from lower merchant pricing in the Alberta market and the cessation of distributions to TransAlta Renewables non-controlling interest. On Oct. 5, 2023, the Company acquired all of the outstanding common shares of TransAlta Renewables not already owned, directly or indirectly.	65
Other non-cash items[2]	9
Other[3]	14
FCF[4] for the three months ended Sept. 30, 2024	**140**

(1) Net interest expense includes interest expense for the period less interest income.

(2) Other non-cash items consists of carbon obligation and contract liabilities. Refer to the Reconciliation of Cash Flow from Operations to FFO and FCF section tables in this MD&A for more details.

(3) Refer to the Reconciliation of Cash Flow from Operations to FFO and FCF section tables in this MD&A for more details.

(4) FCF is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

	9 months ended Sept. 30
FCF for the nine months ended Sept. 30, 2023	769
Lower adjusted EBITDA due to the items noted above.	(375)
Higher current income tax expense due to the full utilization of Canadian non-capital loss carryforwards in 2023 offset by lower earnings before income taxes in 2024.	(68)
Higher net interest expense[1] due to lower capitalized interest as a result of capital projects being completed in the first half of 2024 and lower interest income due to lower cash balances.	(44)
Lower sustaining capital expenditures due to the receipt of a lease incentive related to the relocation of the Company's head office and lower planned major maintenance at our Alberta and Australian gas assets, partially offset by higher major maintenance at our Alberta hydro assets.	25
Lower distributions paid to subsidiaries' non-controlling interests relating to lower TA Cogen net earnings resulting from lower merchant pricing in the Alberta market and the cessation of distributions to TransAlta Renewables non-controlling interest. On Oct. 5, 2023, the Company acquired all of the outstanding common shares of TransAlta Renewables not already owned, directly or indirectly.	170
Other non-cash items[2]	31
Other[3]	13
FCF[4] for the nine months ended Sept. 30, 2024	**521**

(1) Net interest expense includes interest expense for the period less interest income.

(2) Other non-cash items consists of carbon obligation and contract liabilities. Refer to the Reconciliation of Cash Flow from Operations to FFO and FCF section tables in this MD&A for more details.

(3) Refer to the Reconciliation of Cash Flow from Operations to FFO and FCF section tables in this MD&A for more details.

(4) FCF is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Capital Expenditures

We are in a long-cycle, capital-intensive business that requires significant capital expenditures. Our goal is to undertake sustaining capital expenditures that ensure our facilities operate reliably and safely. The following table provides our sustaining capital spend by segment.

	3 months ended Sept. 30		9 months ended Sept. 30	
	2024	**2023**	**2024**	**2023**
Hydro	**21**	11	**34**	25
Wind and Solar	**5**	3	**12**	9
Gas	**6**	15	**20**	32
Energy Transition	**—**	2	**12**	13
Corporate	**3**	5	**(3)**	21
Total sustaining capital expenditures	**35**	36	**75**	100

Total sustaining capital expenditures for the three and nine months ended Sept. 30, 2024, were $1 million and $25 million lower, respectively, compared with the same periods in 2023, primarily due to:

- The receipt of a lease incentive related to the relocation of the Company's head office, included in the Corporate segment; and
- Lower planned major maintenance at our Alberta and Australian gas assets; partially offset by
- Higher major maintenance at our Alberta hydro assets.

Growth and development expenditures are impacted by the timing and construction of the projects within the development pipeline. The following table provides our growth and development spend by segment.

	3 months ended Sept. 30		9 months ended Sept. 30	
	2024	**2023**	**2024**	**2023**
Hydro	**—**	4	**6**	4
Wind and Solar	**6**	94	**54**	518
Gas	**22**	41	**38**	42
Total growth and development expenditures	**28**	139	**98**	564

For the three and nine months ended Sept. 30, 2024, growth and development expenditures were lower compared to the same periods in 2023, as many of the development projects achieved commercial operation in the first and second quarters of 2024.

The White Rock East and Horizon Hill wind facilities were commissioned in the second quarter of 2024. The White Rock West wind facility and Mount Keith 132kV expansion were commissioned in the first quarter of 2024. The 2023 growth and development expenditures also included the Garden Plain wind facility, which was commissioned in August 2023, and the Northern Goldfields solar facilities, which were commissioned in November 2023. Refer to the Strategy and Capability to Deliver Results section of this MD&A for more details.

Significant and Subsequent Events

Mothballing of Sundance Unit 6

On Nov. 4, 2025, the Company provided notice to the AESO that Sundance Unit 6 will be temporarily mothballed on April 1, 2025, for a period of up to two years depending on market conditions. TransAlta maintains the flexibility to return the mothballed unit to service when market fundamentals or opportunities to contract are secured. The unit remains available and fully operational for the upcoming winter season.

Appointment of New Chief Financial Officer ("CFO")

The Board appointed Joel Hunter as Executive Vice President, Finance and CFO, effective July 1, 2024.

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

TransAlta is committed to enhancing shareholder returns through appropriate capital allocation such as share buybacks and its quarterly dividend. In the first quarter of 2024, the Company announced an enhanced common share repurchase program for 2024 allocating up to $150 million, and targeting up to 42 per cent of 2024 FCF guidance to be returned to shareholders in the form of share repurchases and dividends.

On May 27, 2024, the Company announced that it had received approval from the Toronto Stock Exchange to purchase up to a maximum of 14 million common shares during the 12-month period that commenced May 31, 2024, and terminates May 31, 2025. Any common shares purchased under the NCIB will be cancelled.

During the nine months ended Sept. 30, 2024, the Company purchased and cancelled a total of 11,814,700 common shares, at an average price of $9.65 per common share, for a total cost of $114 million, including taxes.

Production Tax Credit ("PTC") Sale Agreements

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

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

The expected annual average EBITDA from these contracts is approximately $78 million (US$57 million).

Horizon Hill Wind Facility Achieved Commercial Operation

On May 21, 2024, the 200 MW Horizon Hill wind facility achieved commercial operation. The facility is located in Logan County, Oklahoma and is fully contracted to Meta for the offtake of 100 per cent of the generation.

White Rock Wind Facilities Achieved Commercial Operation

On Jan. 1, 2024, the 100 MW White Rock West wind facility achieved commercial operation. On April 22, 2024, the 200 MW White Rock East wind facility was also commissioned. The facilities are located in Caddo County, Oklahoma and are contracted under two long-term PPAs with Amazon for the offtake of 100 per cent of the generation from the facilities.

Mount Keith 132kV Expansion Complete

The Mount Keith 132kV expansion project was completed during the first quarter of 2024. The expansion was developed under the existing PPA with BHP Nickel West ("BHP") for a term of 15 years. The expansion will facilitate the connection of additional generating capacity to the transmission network which supports BHP's operations and increases its competitiveness as a supplier of low-carbon nickel.

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 nine months ended Sept. 30:

	3 months ended Sept. 30		9 months ended Sept. 30	
Adjusted EBITDA[(1)]	**2024**	**2023**	**2024**	**2023**
Hydro	**89**	150	**259**	403
Wind and Solar	**44**	37	**221**	175
Gas	**139**	254	**419**	660
Energy Transition	**34**	29	**63**	96
Energy Marketing	**54**	13	**104**	95
Corporate	**(35)**	(30)	**(98)**	(86)
Total adjusted EBITDA[(1)]	**325**	453	**968**	1,343
Earnings before income taxes	**9**	453	**370**	915

(1) This item is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Earnings before income taxes for the three months ended Sept. 30, 2024, decreased by $444 million or 98 per cent, compared to the same period in 2023, primarily due to:

- Lower adjusted EBITDA (as described above);
- Lower unrealized mark-to-market gains in the Gas segment was due to the prior period having significant volume of favourable hedging positions relating to the Alberta portfolio which largely have settled.
- Higher unrealized mark-to-market losses in the Wind and Solar segment was mainly due to the long-term wind energy sales related to the Oklahoma projects in the Central US. The unrealized losses were due to the strengthening forecasted wind capture prices reflected in the period.
- Lower unrealized mark-to-market gains in the Energy Marketing segment is mainly driven by market volatility across North American power and natural gas markets.
- Higher asset impairment charges primarily due to changes in decommissioning and restoration provisions related to discount rates and revisions in estimated costs to decommission retired assets compared to the same periods in 2023.

Earnings before income taxes for the nine months ended Sept. 30, 2024, decreased by $545 million, or 60 per cent, compared to the same period in 2023, primarily due to:

- Lower adjusted EBITDA (as described above);
- Higher asset impairment charges related to discount rates and revisions in estimated costs to decommission retired assets;
- Higher unrealized mark-to-market losses recorded in the Wind and Solar segment primarily related to the long-term wind energy sales related to the Oklahoma projects in the Central US; and
- Lower unrealized mark-to-market gains and lower closed exchange position losses in the Energy Marketing segment mainly driven by market volatility across North American power and natural gas markets; partially offset by
- Lower depreciation and amortization compared to the same periods in 2023 related to revisions of useful lives on certain facilities in prior periods offset by the commercial operation on new facilities during the year and the return to service at Kent Hills.

Hydro

	3 months ended Sept. 30				9 months ended Sept. 30			
	2024	2023	Change		2024	2023	Change	
Gross installed capacity (MW)	922	922	—	— %	922	922	—	— %
LTA generation (GWh)	573	573	—	— %	1,568	1,568	—	— %
Availability (%)	94.3	97.8	(3.5)	(4)%	92.3	95.6	(3.3)	(3)%
Production								
Contract production (GWh)	72	87	(15)	(17)%	196	229	(33)	(14)%
Merchant production (GWh)	422	434	(12)	(3)%	1,075	1,214	(139)	(11)%
Total energy production (GWh)	494	521	(27)	(5)%	1,271	1,443	(172)	(12)%
Ancillary services volumes (GWh)[1]	878	659	219	33 %	2,238	1,872	366	20 %
Alberta hydro assets revenues[2][3]	39	92	(53)	(58)%	111	258	(147)	(57)%
Other hydro assets and other revenues[2][4]	11	17	(6)	(35)%	33	41	(8)	(20)%
Alberta Hydro ancillary services revenues[1]	48	54	(6)	(11)%	108	146	(38)	(26)%
Environmental and tax attributes revenues	8	—	8	100 %	61	9	52	578 %
Revenues[5]	106	163	(57)	(35)%	313	454	(141)	(31)%
Fuel and purchased power	4	4	—	— %	13	14	(1)	(7)%
Gross margin[6]	102	159	(57)	(36)%	300	440	(140)	(32)%
OM&A	13	9	4	44 %	39	35	4	11 %
Taxes, other than income taxes	—	—	—	— %	2	2	—	— %
Adjusted EBITDA[6]	89	150	(61)	(41)%	259	403	(144)	(36)%
Supplemental Information:								
Gross revenues per MWh								
Alberta hydro assets energy ($/MWh)[2][3]	92	226	(134)	(59)%	103	222	(119)	(54)%
Alberta hydro assets ancillary ($/MWh)[1]	55	82	(27)	(33)%	48	78	(30)	(38)%

(1) Ancillary services as described in the AESO Consolidated Authoritative Document Glossary.

(2) Alberta hydro assets include 13 hydro facilities on the Bow and North Saskatchewan river systems. Other hydro assets include facilities in British Columbia, Ontario and Alberta (other than the Alberta hydro assets) and transmission revenues.

(3) The Company entered into forward hedges that are included in the Alberta hydro asset revenues.

(4) Other revenue includes revenues from our transmission business and other contractual arrangements, including the flood mitigation agreement with the Government of Alberta and black start services.

(5) For details of the adjustments to revenues included in adjusted EBITDA refer to the Additional IFRS and Non-IFRS Measures section of this MD&A.

(6) Adjusted EBITDA and gross margin are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS and Non-IFRS Measures section of this MD&A.

Revenues for the three and nine months ended Sept. 30, 2024 decreased compared with the same periods in 2023, broadly inline with expectations, primarily due to:

- Lower power prices in the Alberta market due to the anticipated increased supply of new renewable and combined cycle gas facilities; and
- Lower energy production due to lower water resources in the North Saskatchewan River region and increased planned outages across our fleet compared to the same periods in 2023; partially offset by
- Higher ancillary services volumes due to increased demand by the AESO;
- Realized premiums above spot power prices by capturing high priced hours during periods of volatility and favourable contributions from hedging; and
- Higher environmental and tax attributes revenues due to the increased sales of emission credits to third parties and intercompany sales to the Gas segment.

Adjusted EBITDA for the three and nine months ended Sept. 30, 2024, decreased compared with the same periods in 2023, primarily due to lower revenues as explained by the factors noted above.

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

Wind and Solar

	3 months ended Sept. 30				9 months ended Sept. 30			
	2024	2023	Change		2024	2023	Change	
Gross installed capacity (MW)[1]	**2,584**	**2,036**	*548*	*27 %*	**2,584**	**2,036**	*548*	*27 %*
LTA generation (GWh)	**1,472**	**1,246**	*226*	*18 %*	**4,701**	**3,766**	*935*	*25 %*
Availability (%)	**93.7**	**87.0**	*6.7*	*8 %*	**93.8**	**85.7**	*8.1*	*9 %*
Production								
Contract production (GWh)	**949**	**520**	*429*	*83 %*	**3,251**	**2,022**	*1,229*	*61 %*
Merchant production (GWh)	**172**	**188**	*(16)*	*(9)%*	**867**	**742**	*125*	*17 %*
Total production (GWh)	**1,121**	**708**	*413*	*58 %*	**4,118**	**2,764**	*1,354*	*49 %*
Revenues	**64**	**63**	*1*	*2 %*	**258**	**236**	*22*	*9 %*
Environmental and tax attributes revenues	**13**	**3**	*10*	*333 %*	**61**	**23**	*38*	*165 %*
Revenues[2]	**77**	**66**	*11*	*17 %*	**319**	**259**	*60*	*23 %*
Fuel and purchased power	**5**	**6**	*(1)*	*(17)%*	**22**	**22**	*—*	*— %*
Gross margin[3]	**72**	**60**	*12*	*20 %*	**297**	**237**	*60*	*25 %*
OM&A	**26**	**20**	*6*	*30 %*	**70**	**55**	*15*	*27 %*
Taxes, other than income taxes	**5**	**4**	*1*	*25 %*	**13**	**11**	*2*	*18 %*
Net other operating income	**(3)**	**(1)**	*(2)*	*200 %*	**(7)**	**(4)**	*(3)*	*75 %*
Adjusted EBITDA[3]	**44**	**37**	*7*	*19 %*	**221**	**175**	*46*	*26 %*

(1) Gross installed capacity and availability for 2024 includes the 48 MW Northern Goldfields solar facilities that achieved commercial operation in November 2023, the 100 MW White Rock West and 200 MW White Rock East wind facilities that achieved commercial operation in January and April 2024, respectively, and the 200 MW Horizon Hill wind facility that achieved commercial operation in May 2024.

(2) For details of the adjustments to revenues included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(3) Adjusted EBITDA and gross margin are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS and Non-IFRS Measures section of this MD&A.

Revenues for the three and nine months ended Sept. 30, 2024, increased compared with the same periods in 2023 primarily due to:

- Higher environmental and tax attributes revenues due to the commencement of the recently announced sales agreements to transfer production tax credits from the Oklahoma wind facilities to taxable US counterparties;
- Commercial operation of the White Rock and Horizon Hill wind facilities and the Northern Goldfields solar facilities;
- Higher production from the return to service of the Kent Hills wind facilities; partially offset by
- Lower realized power prices in the Alberta market due to the increased supply of new renewable and combined cycle gas facilities.

Adjusted EBITDA for the three and nine months ended Sept. 30, 2024, increased compared with the same periods in 2023, primarily due to:

- Higher revenues as explained by the factors above; partially offset by
- Higher OM&A related to the addition of the Garden Plain, White Rock and Horizon Hill wind facilities and the Northern Goldfields solar facilities, salary escalations, higher insurance costs and long-term service agreement escalations.

Gas

	3 months ended Sept. 30				9 months ended Sept. 30			
	2024	2023	Change		2024	2023	Change	
Gross installed capacity (MW)	3,087	3,084	3	— %	3,087	3,084	3	— %
Availability (%)	96.3	94.6	1.7	2 %	95.4	92.3	3.1	3 %
Production								
Contract sales volume (GWh)	1,603	951	652	69 %	4,942	2,959	1,983	67 %
Merchant sales volume (GWh)	1,736	2,373	(637)	(27)%	5,189	6,271	(1,082)	(17)%
Purchased power (GWh)(1)	(220)	(30)	(190)	633 %	(689)	(249)	(440)	177 %
Total production (GWh)	3,119	3,294	(175)	(5)%	9,442	8,981	461	5 %
Revenues(2)	314	430	(116)	(27)%	971	1,185	(214)	(18)%
Fuel and purchased power(2)	99	110	(11)	(10)%	336	323	13	4 %
Carbon compliance	40	28	12	43 %	106	85	21	25 %
Gross margin(3)	175	292	(117)	(40)%	529	777	(248)	(32)%
OM&A	43	45	(2)	(4)%	131	136	(5)	(4)%
Taxes, other than income taxes	3	3	—	— %	9	11	(2)	(18)%
Net other operating income	(10)	(10)	—	— %	(30)	(30)	—	— %
Adjusted EBITDA(3)	139	254	(115)	(45)%	419	660	(241)	(37)%

(1) Power required to fulfill contractual obligations is included in purchased power.

(2) For details of the adjustments to revenues and fuel and purchased power included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(3) Adjusted EBITDA and gross margin are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Revenues for the three and nine months ended Sept. 30, 2024, decreased compared with the same periods in 2023, broadly inline with expectations. The decrease was primarily due to:

- Lower production due to increased dispatch optimization driven by power prices from the Alberta Gas fleet;
- Lower capacity payments in 2024 for Southern Cross Energy in Australia due to the scheduled conclusion on Dec. 31, 2023, of the demand capacity charge under the customer contract, partially offset by the commencement in March 2024 of capacity payments for the Mount Keith 132kV expansion; partially offset by
- Higher volume of favourable hedging positions settled, which generated positive contributions over settled spot prices in Alberta;
- Higher production in Ontario; and
- Lower planned outages in Alberta.

Adjusted EBITDA for the three and nine months ended Sept. 30, 2024, decreased compared with the same periods in 2023, primarily due to:

- Lower revenues explained above; and
- An increase in the carbon price from $65 per tonne to $80 per tonne, impacting gross margin from our Canadian gas assets; partially offset by
- Lower natural gas prices; and
- The utilization of emission credits in the second quarter of 2024 to settle a portion of our 2023 GHG obligation.

Energy Transition

	3 months ended Sept. 30				9 months ended Sept. 30			
	2024	2023	Change		2024	2023	Change	
Gross installed capacity (MW)	671	671	—	— %	671	671	—	— %
Availability (%)	90.0	86.2	3.8	4 %	76.1	79.8	(3.7)	(5)%
Production								
Contract sales volume (GWh)	840	839	1	— %	2,499	2,489	10	— %
Merchant sales volume (GWh)	1,087	1,244	(157)	(13)%	2,064	3,243	(1,179)	(36)%
Purchased power (GWh)(1)	(949)	(928)	(21)	2 %	(2,782)	(2,674)	(108)	4 %
Total production (GWh)	978	1,155	(177)	(15)%	1,781	3,058	(1,277)	(42)%
Revenues(2)	157	193	(36)	(19)%	433	564	(131)	(23)%
Fuel and purchased power	104	148	(44)	(30)%	316	419	(103)	(25)%
Carbon compliance	1	—	1	100 %	1	—	1	100 %
Gross margin(3)	52	45	7	16 %	116	145	(29)	(20)%
OM&A	17	15	2	13 %	50	46	4	9 %
Taxes, other than income taxes	1	1	—	— %	3	3	—	— %
Adjusted EBITDA(3)	34	29	5	17 %	63	96	(33)	(34)%
Supplemental information:								
Highvale mine reclamation spend	2	3	(1)	(33)%	8	9	(1)	(11)%
Centralia mine reclamation spend	5	3	2	67 %	12	10	2	20 %

(1) All of the power produced by Centralia is sold by the Energy Marketing segment for physical market delivery, which is shown as merchant sales volumes. Power required to fulfil contractual obligations is included in purchased power. Total production from the facility includes the net result of merchant sales volumes and purchased power.

(2) For details of the adjustments to revenues included in adjusted EBITDA refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(3) Adjusted EBITDA and gross margin are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Revenues for the three and nine months ended Sept. 30, 2024, decreased compared with the same periods in 2023, primarily due to increased economic dispatch due to lower market prices which negatively impacted merchant production.

Adjusted EBITDA for the three months ended Sept. 30, 2024, increased compared with the same period in 2023, primarily due to:

- Lower purchased power costs driven by lower Mid-C prices on repurchases of power and lower production; partially offset by
- Lower revenues as explained by the factors above.

Adjusted EBITDA for the nine months ended Sept. 30, 2024, decreased compared with the same period in 2023, primarily due to:

- Lower revenues as explained by the factors above; partially offset by
- Lower fuel costs due to lower production volumes.

Mine reclamation spend for the three and nine months ended Sept. 30, 2024, was consistent compared with the same periods in 2023.

Energy Marketing

	3 months ended Sept. 30				9 months ended Sept. 30			
	2024	**2023**	**Change**		**2024**	**2023**	**Change**	
Revenues(1)	**64**	**26**	*38*	*146 %*	**133**	**128**	*5*	*4 %*
OM&A	**10**	**13**	*(3)*	*(23)%*	**29**	**33**	*(4)*	*(12)%*
Adjusted EBITDA(2)	**54**	**13**	*41*	*315 %*	**104**	**95**	*9*	*9 %*

(1) For details of the adjustments to revenues included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A. Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Adjusted EBITDA for the three and nine months ended Sept. 30, 2024, increased compared with the same periods in 2023, primarily due to favourable market volatility across North American power and natural gas markets and higher realized settled trades in the third quarter of 2024 in comparison to the prior period.

The Company was able to capitalize on volatility in the trading of both physical and financial power and gas products across North American deregulated markets while maintaining the overall risk profile of the business unit.

Corporate

	3 months ended Sept. 30				9 months ended Sept. 30			
	2024	**2023**	**Change**		**2024**	**2023**	**Change**	
OM&A(1)	**34**	**30**	*4*	*13%*	**97**	**86**	*11*	*13%*
Taxes, other than income taxes	**1**	**—**	*1*	*100%*	**1**	**—**	*1*	*100%*
Adjusted EBITDA(2)	**(35)**	**(30)**	*(5)*	*17%*	**(98)**	**(86)**	*(12)*	*14%*

(1) For details of the adjustments to OM&A included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Adjusted EBITDA for the three and nine months ended Sept. 30, 2024, decreased compared with the same periods in 2023, primarily due to:

- Increased spending for planning and design of the ERP upgrade program, and to support strategic and growth initiatives.

Performance by Segment with Supplemental Geographical Information

The following table provides adjusted EBITDA performance of our facilities across the regions we operate in:

3 months ended Sept. 30, 2024	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	86	3	89	(2)	54	(35)	195
Canada, excluding Alberta	3	12	22	—	—	—	37
US	—	27	3	36	—	—	66
Australia	—	2	25	—	—	—	27
Adjusted EBITDA(1)	**89**	**44**	**139**	**34**	**54**	**(35)**	**325**
Earnings before income taxes							**9**

3 months ended Sept. 30, 2023	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	146	10	197	(3)	13	(30)	333
Canada, excluding Alberta	4	11	22	—	—	—	37
US	—	16	3	32	—	—	51
Australia	—	—	32	—	—	—	32
Adjusted EBITDA(1)	150	37	254	29	13	(30)	453
Earnings before income taxes							453

9 months ended Sept. 30, 2024	Hydro	Wind & Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	253	43	267	(7)	104	(98)	562
Canada, excluding Alberta	6	80	72	—	—	—	158
US	—	92	9	70	—	—	171
Australia	—	6	71	—	—	—	77
Adjusted EBITDA(1)	**259**	**221**	**419**	**63**	**104**	**(98)**	**968**
Earnings before income taxes							**370**

9 months ended Sept. 30, 2023	Hydro	Wind & Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	396	53	484	(7)	95	(86)	935
Canada, excluding Alberta	7	61	68	—	—	—	136
US	—	61	7	103	—	—	171
Australia	—	—	101	—	—	—	101
Adjusted EBITDA(1)	403	175	660	96	95	(86)	1,343
Earnings before income taxes							915

(1) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Presenting this from period to period provides management and investors with the ability to evaluate earnings (loss) trends more readily in comparison with prior periods' results. Refer to the Segmented Financial Performance and Operating Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. Also, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Optimization of the Alberta Portfolio

Our merchant exposure is primarily in Alberta, where 49 per cent of our capacity is located and 76 per cent of which is available to participate in the merchant market. Our portfolio of merchant assets in Alberta consists of hydro facilities, wind facilities, a battery storage facility and natural gas generation facilities.

Generating capacity in Alberta is subject to market forces. Power from commercial generation is cleared through a wholesale electricity market and dispatched in accordance with an economic merit order administered by the 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 and 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 thermal 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 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 will monetize its hedged or contract positions. This results in a change in revenue not correlating with a change in production. In the three and nine months ended Sept. 30, 2024, there were periods of lower market prices, and the Company opted not to generate production from the thermal fleet and as a result, the thermal generation sold through C&I contracts and financial hedges exceeded the actual merchant production generated.

The Alberta hydro fleet provides ancillary services and grid reliability products such as black start services, in the event of a system-wide blackout in the province, and drought mitigation, by systematically regulating river flows.

Our Alberta wind and hydro fleets provide a steady stream of environmental credits to meet ESG goals.

	2024					2023				
3 months ended Sept. 30	**Hydro**	**Wind & Solar**	**Gas**	**Energy Transition**	**Total**	**Hydro**	**Wind & Solar**	**Gas**	**Energy Transition**	**Total**
Gross installed capacity (MW)	**834**	**766**	**1,963**	**—**	**3,563**	834	766	1,960	—	3,560
Total production[1] (GWh)	**422**	**332**	**2,072**	**—**	**2,826**	434	323	2,335	—	3,092
Contract production (GWh)	**—**	**160**	**587**	**—**	**747**	—	135	137	—	272
Merchant production (GWh)	**422**	**172**	**1,485**	**—**	**2,079**	434	188	2,198	—	2,820
Purchased power (GWh)	**—**	**—**	**(207)**	**—**	**(207)**	—	—	(37)	—	(37)
Hedged production (GWh)	**159**	**22**	**2,184**	**—**	**2,365**	148	32	1,939	—	2,119
Production contracted or hedged (%)	**38%**	**55%**	**134%**	**—%**	**110%**	34%	52%	89%	—%	77%
Hedged production as a percentage of gross installed capacity (%)	**9%**	**1%**	**51%**	**—%**	**40%**	8%	2%	45%	—%	27%
Revenues[2] ($)	**101**	**14**	**212**	**1**	**328**	157	22	325	2	506
Fuel ($)	**2**	**2**	**65**	**—**	**69**	2	3	79	—	84
Purchased power ($)	**1**	**—**	**12**	**—**	**13**	1	1	8	—	10
Carbon compliance ($)	**—**	**—**	**34**	**—**	**34**	—	—	30	—	30
Gross margin ($)	**98**	**12**	**101**	**1**	**212**	154	18	208	2	382

(1) Total production includes contract production and merchant production.

(2) Revenues have been adjusted to exclude the impact of unrealized mark-to-market gains or losses and to include realized gains and losses on closed exchange positions.

9 months ended Sept. 30	2024 Hydro	2024 Wind & Solar	2024 Gas	2024 Energy Transition	2024 Total	2023 Hydro	2023 Wind & Solar	2023 Gas	2023 Energy Transition	2023 Total
Gross installed capacity (MW)	834	766	1,963	—	3,563	834	766	1,960	—	3,560
Total production[1] (GWh)	1,076	1,362	6,221	—	8,659	1,214	1,163	6,394	—	8,771
Contract production (GWh)	—	671	1,729	—	2,400	—	421	423	—	844
Merchant production (GWh)	1,076	691	4,492	—	6,259	1,214	742	5,971	—	7,927
Purchased power (GWh)	—	—	(633)	—	(633)	—	—	(100)	—	(100)
Hedged production (GWh)	353	91	5,997	—	6,441	319	139	5,489	—	5,947
Production contracted or hedged (%)	33%	56%	124%	—%	102%	26%	48%	92%	—%	77%
Hedged production as a percentage of gross installed capacity (%)	7%	2%	47%	—%	36%	6%	3%	43%	—%	26%
Revenues[2][3] ($)	298	81	652	4	1,035	438	92	862	4	1,396
Fuel ($)	5	8	211	—	224	5	12	231	—	248
Purchased power ($)	6	2	46	—	54	7	3	24	—	34
Carbon compliance ($)[3]	—	—	91	1	92	—	—	81	—	81
Gross margin ($)	287	71	304	3	665	426	77	526	4	1,033

(1) Total production includes contract production and merchant production.

(2) Revenues have been adjusted to exclude the impact of unrealized mark-to-market gains or losses and to include realized gains and losses on closed exchange positions.

(3) The intercompany sales of emission credits from the Hydro segment to the Gas segment is eliminated on consolidation in the Corporate segment. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A

Total production for the three and nine months ended Sept. 30, 2024, was 2,826 GWh and 8,659 GWh, respectively, compared to 3,092 GWh and 8,771 GWh, respectively, in the same periods in 2023. The decrease of 266 GWh and 112 GWh, or nine per cent and one per cent, respectively, was primarily due to:

- Lower production resulting from lower power prices in the Gas segment;
- Lower production from the Alberta hydro assets due to lower water resources and increased planned outages compared to same period in the prior year; partially offset by
- The addition of the Garden Plain wind facility which was commissioned in August 2023.

Hedged production volumes for the three and nine months ended Sept. 30, 2024, increased compared to the same periods in 2023. In anticipation of the risk of lower prices in 2024, the Company deployed a defensive strategy to increase financial hedges for the merchant portfolio at attractive margins. Realized gains and losses on financial hedges are included in Revenues in the table above.

Gross margin for the three and nine months ended Sept. 30, 2024, was $212 million and $665 million, respectively, compared to $382 million and $1,033 million, respectively in the same periods in 2023. For the three months ended Sept. 30, 2024, the decrease of $170 million or 45 per cent, was primarily due to:

- The impacts of lower Alberta spot power prices; partially offset by
- Higher environmental and tax attributes revenues due to increased sales of emission credits to third parties and intercompany sales from the Hydro segment to the Gas segment;
- Higher gains realized on financial power hedges settled in the period; and
- Lower natural gas costs.

For the nine months ended Sept. 30, 2024, the decrease of $368 million or 36 per cent, was primarily due to:

- The impacts of lower Alberta spot power prices; partially offset by
- Higher gains realized on financial hedges settled in the period;
- Higher environmental and tax attributes revenues due to the increased sales of emission credits to third parties and intercompany sales from the Hydro segment to the Gas segment; and
- The utilization of emission credits in the Gas segment in the second quarter of 2024, to settle a portion of our 2023 GHG obligation.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2024	2023	**2024**	**2023**
Alberta Market				
Spot power price average per MWh	**55**	152	**67**	151
Natural gas price (AECO) per GJ	**0.67**	2.49	**1.24**	2.65
Carbon compliance price per tonne	**80**	65	**80**	65
Alberta Portfolio Results				
Realized merchant power price per MWh(1)	**90**	140	**91**	136
Hydro energy spot power price per MWh	**83**	195	**95**	192
Wind energy spot power price per MWh	**35**	103	**40**	89
Gas spot power price per MWh	**73**	173	**84**	174
Hydro ancillary spot price per MWh	**55**	82	**48**	78
Hedged power price average per MWh	**85**	120	**86**	117
Hedged volume (GWh)	**2,365**	2,119	**6,441**	5,947
Fuel cost per MWh(2)	**34**	36	**36**	39
Carbon compliance cost per MWh(3)	**19**	13	**16**	13

(1) Realized merchant power price for the Alberta electricity portfolio is the average price realized as a result of the Company's merchant power sales and portfolio optimization activities (excluding assets under long-term contract and ancillary revenues) divided by total merchant GWh produced.

(2) Fuel cost per MWh is calculated on production from carbon-emitting generation in the Gas and Energy Transition segments.

(3) Carbon compliance cost per MWh is calculated on production from carbon-emitting generation, as well as power purchased, in the Gas and Energy Transition segments.

The average spot power price per MWh for the three and nine months ended Sept. 30, 2024, decreased from $152 and $151 per MWh, respectively, in 2023 to $55 per MWh and $67 per MWh, respectively, in 2024, primarily due to:

- Higher generation from the addition of new wind and solar and gas supply in the market compared to the prior periods;
- Lower natural gas prices; and
- Milder weather compared with the same periods in 2023.

The realized merchant power price per MWh of production for the three and nine months ended Sept. 30, 2024, decreased by $50 per MWh and $45 per MWh, respectively, compared to the same periods in 2023, although was significantly higher than average spot power prices during the quarter, primarily due to:

- Lower average spot power prices as explained above; and
- Lower hedge prices compared to the same periods in 2023.

Fuel cost per MWh for the three and nine months ended Sept. 30, 2024, decreased by $2 per MWh and $3 per MWh, respectively, compared to the same periods in 2023, primarily due to lower natural gas prices.

Carbon compliance cost per MWh of production for the three and nine months ended Sept. 30, 2024, increased by $6 per MWh and $3 per MWh, respectively, compared to the same periods in 2023, primarily due to:

- The increase in carbon pricing from $65 per tonne to $80 per tonne; partially offset by
- The utilization of emission credits in the second quarter of 2024 to settle a portion of the 2023 GHG obligation.

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; 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. For the Alberta hydro assets, hydro production is impacted by the optimization of water supply to facilitate generation during the higher demand periods of summer and winter. Inversely, wind speeds are historically greater during the cold winter months and lower in the warm summer months.

	Q4 2023	Q1 2024	Q2 2024	Q3 2024
Revenues	624	947	582	**638**
Carbon compliance	27	40	(8)	**41**
OM&A	150	134	144	**143**
Depreciation and amortization	132	124	131	**133**
Earnings (loss) before income taxes	(35)	267	94	**9**
Net earnings (loss) attributable to common shareholders	(84)	222	56	**(36)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	(0.27)	0.72	0.18	**(0.12)**
Cash flow from operating activities	310	244	108	**229**

	Q4 2022	Q1 2023	Q2 2023	Q3 2023
Revenues	854	1,089	625	1,017
Carbon compliance	27	32	25	28
OM&A	157	124	134	131
Depreciation and amortization	188	176	173	140
Earnings before income taxes	7	383	79	453
Net earnings (loss) attributable to common shareholders	(163)	294	62	372
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	(0.61)	1.10	0.23	1.41
Cash from operating activities	351	462	11	681

(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:

- 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 in the first quarter of 2024 and the White Rock East and Horizon Hill wind facilities in the second quarter of 2024; and
- The rehabilitation of the Kent Hills 1 and 2 wind facilities in 2022 through to the fourth quarter of 2023.

In addition to the items described above, revenues have been impacted by:

- Higher production in the first, second and third quarters of 2024, compared to the same periods in the prior year; and
- Lower realized pricing in the fourth quarter of 2023 and the first, second and third quarters of 2024, compared to the same periods in the prior years, due to lower volumes of power imported from adjacent markets and higher power prices during periods of overlapping outages and lower renewable operations. Pricing was also impacted by additions of new natural gas, wind and solar supply in the market.
- The affects of unrealized mark-to-market gains and losses from hedging and derivative positions.

Carbon compliance costs have been impacted by:

- Higher costs of carbon per tonne. In 2022, the cost of carbon was $50 per tonne and increased to $65 per tonne in 2023 and to $80 per tonne in 2024.
- In the second quarter of 2024, carbon compliance costs were reduced by utilizing internally generated and

externally purchased emission credits to settle a portion of the 2023 GHG obligation.

OM&A has been impacted by higher costs in the first, second and third quarters of 2024, compared to the same periods in the prior year due to higher spending on strategic and growth initiatives.

Depreciation in the last four quarters decreased compared to the same periods in the prior year due to revisions in useful lives on certain facilities that occurred in the third quarter of 2023;

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

- The items described above;
- Lower natural gas prices in the last four quarters compared to the same periods in the prior year;
- The effects of changes in decommissioning provisions for retired assets due to changes in estimated cash flows in the third quarter of 2023 and 2024, and changes in useful lives, recognized in the third quarter of 2023;
- Liquidated damages recoverable as a result of turbine availability being below the contractual target at the Windrise wind facility recorded in all quarters, with higher amounts recognized in the first quarter of 2023; and
- Gains relating to the sale of assets being recognized in the fourth quarter of 2022.

Net earnings (loss) attributable to common shareholders has been impacted by fluctuations in current and deferred tax expense with earnings before tax across the quarters.

Strategy and Capability to Deliver Results

Our strategic focus is to invest in clean and reliable electricity solutions that meet the needs and objectives of our customers and communities. We invest in a disciplined and prudent manner to deliver appropriate risk-adjusted returns for our shareholders. To support this strategy, we maintain a robust pipeline of approximately 5 GW of project opportunities focused on hydro, wind, solar, energy storage and gas.

On Nov. 21, 2023, the Company updated its five-year strategic growth targets and Clean Electricity Growth Plan. The Company established six strategic priorities to focus our path from 2024 to 2028. Refer to the Strategy and Capacity to Deliver Results and Strategic Priorities and Clean Electricity Growth Plan to 2028 sections of the Annual MD&A for further details.

Capital Allocation Decisions

In February 2024, the Company announced an enhanced common share repurchase program for 2024 of up to $150 million towards the repurchase of common shares. Given the current environment, the Company believes the enhanced share repurchase plan is an appropriate and balanced use of capital, while still permitting the Company to pursue growth opportunities with appropriate returns. We remain committed to our capital allocation priorities and returning value to our shareholders.

During the nine months ended Sept. 30, 2024, the Company purchased and cancelled a total of 11,814,700 common shares, at an average price of $9.65 per common share, for a total cost of $114 million, including taxes.

Advanced-Stage Development

Advanced-stage development projects have detailed engineering, advanced positions in the interconnection queue and/or are progressing offtake opportunities. Projects in advanced-stage development are progressing towards final investment decision and do not have final approval from the Board of Directors at time of reporting.

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

Project	Type	Region	Target investment date	MW
Tempest	Wind	Alberta	On hold	100
WaterCharger	Battery Storage	Alberta	On hold	180
Pinnacle 1 & 2	Gas	Alberta	On hold	44

Early-Stage Development

Early-stage development projects are in the early stages and may or may not move ahead. Generally, these projects will have:

- Collected meteorological data;
- Begun securing land control;
- Started environmental studies;
- Confirmed appropriate access to transmission; and
- Started preliminary permitting and other regulatory approval processes.

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

Project	Type	Region	Target FID[1]	MW
Canada				
New Brunswick Battery	Battery	New Brunswick	2026	10
Sunhills Solar	Solar	Alberta	2026	170
Tent Mountain Pumped Storage[2]	Hydro	Alberta	2029	160
Provost	Wind	Alberta	2027	170
Red Rock	Wind	Alberta	2027	100
Willow Creek 1	Wind	Alberta	2027	70
Willow Creek 2	Wind	Alberta	2027	70
Antelope Coulee	Wind	Saskatchewan	2027+	200
Other Canadian Opportunities	Wind	Various	2026+	190
Brazeau Pumped Hydro	Hydro	Alberta	TBD	300-900
Alberta Thermal Redevelopment[3]	Various	Alberta	TBD	400-1200
		Total		**1,840 - 3,240**
United States				
Swan Creek	Wind	Nebraska	2025	126
Dos Rios	Wind	Oklahoma	2025	242
Cotton Belle 1	Solar	Texas	2026	104
Cotton Belle 2	Solar	Texas	2026	81
Square Top	Solar	Oklahoma	2026	195
Old Town	Wind	Illinois	2026	185
Canadian River	Wind	Oklahoma	2026	250
Big Timber	Wind	Pennsylvania	2026	50
Trapper Valley	Wind	Wyoming	2027+	225
Wild Waters	Wind	Minnesota	2027+	40
Other US Opportunities	Wind	Various	2026+	144
Centralia Site Redevelopment[3]	Various	Washington	TBD	500-1000
		Total		**2,142 - 2,642**
Australia				
Boodarie Solar	Solar	Western Australia	2025	50
Other Australian Opportunities	Gas, Solar, Transmission	Western Australia	2025+	115
		Total		**165**
Canada, United States and Australia		**Total**		**4,147 - 6,047**

(1) Target Final Investment Decision ("FID") date is to be determined ("TBD").
(2) This represents the Company's 50 per cent interest in Tent Mountain Renewable Energy Complex.
(3) The Company is currently evaluating redevelopment opportunities at these brownfield sites.

Projects under Construction

The following project has been approved by the Board of Directors, has an executed power purchase agreement ("PPA") and is currently under construction. This project will be financed through existing liquidity in the near term.

We will continue to explore permanent financing solutions on an asset-by-asset basis.

				Total project (millions)					
Project	Type	Region	MW	Estimated spend	Spent to date	Target completion date	PPA Term	Average annual EBITDA[1]	Status
Australia									
Mount Keith West Network Upgrade	Transmission	WA	n/a	AU$37 — AU$40	AU$14	Q2 2025	14	AU$6 - AU$7	• Major equipment orders placed • Detailed design and execution planning underway • On track to be completed on schedule
Total[2]			**n/a**	**$34 — $36**	**$12**			**$6 - $7**	

(1) This item is not defined and has no standardized meaning under IFRS and is forward-looking. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion.

(2) Total expected spending and average annual EBITDA were converted using a Canadian dollar forward exchange rate for 2024. Spend to date was converted using the period-end closing rate.

Financial Position

The following table highlights significant changes in the unaudited interim condensed consolidated statements of financial position from Dec. 31, 2023, to Sept. 30, 2024:

	Sept. 30, 2024	Dec. 31, 2023	Increase/(decrease)
Assets			
Current assets			
Cash and cash equivalents	**401**	348	53
Risk management assets	**232**	151	81
Other current assets[(1)]	**1,057**	1,081	(24)
Total current assets	**1,690**	1,580	110
Non-current assets			
Risk management assets	**100**	52	48
Property, plant and equipment, net	**5,545**	5,714	(169)
Other non-current assets[(2)]	**1,319**	1,313	6
Total non-current assets	**6,964**	7,079	(115)
Total assets	**8,654**	8,659	(5)
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	**640**	797	(157)
Risk management liabilities	**193**	314	(121)
Exchangeable securities[(3)]	**747**	—	747
Other current liabilities[(4)]	**695**	631	64
Total current liabilities	**2,275**	1,742	533
Non-current liabilities			
Credit facilities, long-term debt and lease liabilities	**2,879**	2,934	(55)
Exchangeable securities	**—**	744	(744)
Risk management liabilities (long-term)	**299**	274	25
Defined benefit obligation and other long-term liabilities	**212**	251	(39)
Other non-current liabilities[(5)]	**1,068**	1,050	18
Total non-current liabilities	**4,458**	5,253	(795)
Total liabilities	**6,733**	6,995	(262)
Equity			
Equity attributable to shareholders	**1,814**	1,537	277
Non-controlling interests	**107**	127	(20)
Total equity	**1,921**	1,664	257
Total liabilities and equity	**8,654**	8,659	(5)

(1) Includes trade and other receivables, restricted cash, prepaid expenses and other, and inventory.

(2) Includes investments, long-term portion of finance lease receivable, right-of-use assets, intangible assets, goodwill, deferred income tax assets and other assets.

(3) Classified as current as their conversion option can be exercised at any time after Jan. 1, 2025 at Brookfield's option, although there is no obligation to deliver cash. Refer to the Accounting Changes section of this MD&A for more details.

(4) Includes bank overdraft, current portion of decommissioning and other provisions, current portion of contract liabilities, income taxes payable, dividends payable and current portion of long-term debt and lease liabilities.

(5) Includes long-term decommissioning and other provisions, deferred income tax liabilities and contract liabilities.

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 $585 million as at Sept. 30, 2024 (Dec. 31, 2023 – deficit of $162 million).

Current assets increased by $110 million to $1,690 million as at Sept. 30, 2024, from $1,580 million as at Dec. 31, 2023, primarily due to:

- Higher risk management assets mainly due to volatility in market prices; and
- Higher cash and cash equivalents.

Current liabilities increased by $533 million from $1,742 million as at Dec. 31, 2023, to $2,275 million as at Sept. 30, 2024, mainly due to:

- The Exchangeable Securities being classified as current as their conversion option can be exercised at any time after Jan. 1, 2025 at Brookfield's option, although there is no obligation to deliver cash equivalent resources and the holder cannot call for repayment. Refer to the Accounting Changes section of this MD&A for more details; partially offset by
- Lower accounts payable and accrued liabilities mainly due to lower cost accruals and lower capital spend; and
- Lower risk management liabilities due to volatility in market prices.

Non-Current Assets

Non-current assets as at Sept. 30, 2024, were $6,964 million, a decrease of $115 million from $7,079 million as at Dec. 31, 2023, primarily due to:

- Lower property, plant and equipment ("PP&E") resulting from depreciation; partially offset by
- Capital additions of $200 million; and
- Higher risk management assets mainly due to volatility in market prices.

Non-Current Liabilities

Non-current liabilities as at Sept. 30, 2024, were $4,458 million, a decrease of $795 million from $5,253 million as at Dec. 31, 2023, primarily due to:

- The Exchangeable Securities being classified to current liabilities;
- Decrease in net borrowings under credit facilities;
- Lower retail power contract liabilities resulting from amortization recognized on delivered volumes; partially offset by
- Higher risk management liabilities due to volatility in market pricing across multiple markets.

Total Equity

As at Sept. 30, 2024, the increase in total equity of $257 million was due to:

- Net earnings of $282 million; and
- Net gains on derivatives from cash flow hedges of $147 million; partially offset by
- Share repurchases under the NCIB of $114 million; and
- Distributions to non-controlling interests of $34 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:

	Sept. 30, 2024		Dec. 31, 2023	
	$	%	$	%
Net senior unsecured debt				
Recourse debt - CAD debentures	**251**	**4**	251	5
Recourse debt - US senior notes	**931**	**16**	911	17
Credit facilities	**397**	**7**	397	7
Less: cash and cash equivalents[1]	**(401)**	**(8)**	(345)	(6)
Less: other cash and liquid assets[2]	**2**	**—**	5	—
Net senior unsecured debt	**1,180**	**19**	1,219	23
Other debt liabilities				
Exchangeable debentures	**347**	**6**	344	6
Non-recourse debt				
TAPC Holdings LP bond	**78**	**1**	85	1
Pingston bond	**39**	**1**	39	1
Melancthon Wolfe Wind bond	**151**	**3**	168	3
New Richmond Wind bond	**98**	**2**	103	2
Kent Hills Wind bond	**183**	**3**	193	3
Windrise Wind bond	**160**	**3**	164	3
South Hedland non-recourse debt	**696**	**12**	691	13
OCP bond	**192**	**3**	217	4
OCP LP restricted cash[3]	**(17)**	**—**	(17)	—
US tax equity financing	**98**	**2**	104	1
Lease liabilities	**144**	**3**	143	3
Total consolidated net debt[4][5][6]	**3,349**	**58**	3,453	63
Exchangeable preferred securities[6]	**400**	**7**	400	7
Equity attributable to shareholders				
Common shares	**3,191**	**57**	3,285	60
Preferred shares	**942**	**17**	942	17
Contributed surplus, deficit and accumulated other comprehensive loss	**(2,319)**	**(41)**	(2,690)	(49)
Non-controlling interests	**107**	**2**	127	2
Total capital	**5,670**	**100**	5,517	100

(1) Cash and cash equivalents is net of bank overdraft.

(2) Includes the fair value of economic and designated hedging instruments on debt, as the carrying value of the related debt is impacted by changes in foreign exchange rates.

(3) Principal portion of the TransAlta OCP LP restricted cash related to the TransAlta OCP LP bonds as this cash is restricted specifically to repay outstanding debt.

(4) These items are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion, including reconciliations to measures calculated in accordance with IFRS.

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

(6) The total consolidated net debt excludes the exchangeable preferred securities as they are considered equity with dividend payments for credit purposes.

Between 2024 and 2026, we have $720 million of debt maturing, including $400 million of recourse debt relating to the Term Facility, with the balance mainly related to scheduled non-recourse debt repayments. The $750 million of Exchangeable Securities can be exchanged at the earliest on Jan. 1, 2025.

Credit Facilities

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

As at Sept. 30, 2024		Utilized			
Credit facilities	Facility size	Outstanding letters of credit[1]	Cash drawings	Available capacity	Maturity date
Committed					
Syndicated credit facility	1,950	455	—	1,495	Q2 2028
Bilateral credit facilities	240	158		82	Q2 2026
Term Facility	400	—	400	—	Q3 2025
Total committed	**2,590**	**613**	**400**	**1,577**	
Non-committed					
Demand facilities	400	204	—	196	N/A
Total non-committed	**400**	**204**	**—**	**196**	

(1) TransAlta has obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, pension plan obligations, construction projects and purchase obligations. Letters of credit drawn against the non-committed facilities reduce available capacity under the committed syndicated credit facilities.

In the second quarter of 2024, the Term Facility of $400 million was renewed with the maturity extended by one year to September 2025. The syndicated credit facility and bilateral credit facilities were also extended by one year to June 2028 and June 2026, respectively.

Non-Recourse Debt and Other

The Melancthon Wolfe Wind LP, TAPC Holdings LP, New Richmond Wind LP, Kent Hills Wind LP, Windrise Wind LP, TEC Hedland Pty Ltd. non-recourse bonds, and TransAlta OCP LP bonds, 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 third quarter of 2024, with the exception of Kent Hills Wind LP. The funds in the entity that have accumulated since the third quarter test will remain there until the next debt service coverage test can be performed in the fourth quarter of 2024. At Sept. 30, 2024, $56 million (Dec. 31, 2023 – $79 million) of cash was subject to these financial restrictions.

At Sept. 30, 2024, $7 million (AU$8 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 Sept. 30		9 months ended Sept. 30	
	2024	**2023**	**2024**	**2023**
Interest income	**4**	16	**19**	47
Interest on debt	**49**	51	**148**	152
Interest on exchangeable debentures	**7**	7	**22**	22
Interest on exchangeable preferred shares	**7**	7	**21**	21
Capitalized interest	**—**	(15)	**(16)**	(41)
Interest on lease liabilities	**2**	3	**7**	7
Credit facility fees, bank charges and other interest	**6**	6	**14**	17
Accretion of provisions	**12**	10	**36**	37
Interest expense	**83**	69	**232**	215

Interest income was lower due to lower cash balances. Interest expense was higher when compared to the same period in 2023, primarily due to lower capitalized interest as a result of capital projects being completed in the first half of 2024.

Share Capital

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

	Number of shares (millions)		
As at	**Nov. 4, 2024**	**Sept. 30, 2024**	**Dec. 31, 2023[1]**
Common shares issued and outstanding, end of period	**298.4**	**298.5**	308.6
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[2]	**0.4**	**0.4**	0.4
Preferred shares issued and outstanding	**39.0**	**39.0**	39.0

(1) Common shares issued and outstanding as at Dec. 31, 2023, excludes the provision for repurchase of 1.7 million common shares under the ASPP.

(2) Brookfield Renewable Partners or its affiliates (collectively "Brookfield") invested $400 million in consideration for redeemable, retractable, first preferred shares which form part of the Exchangeable Securities. For accounting purposes, these preferred shares are considered debt and disclosed as such in the unaudited interim condensed consolidated financial statements.

Non-Controlling Interests

On Oct. 5, 2023, the Company acquired all of the outstanding common shares of TransAlta Renewables not already owned, directly or indirectly, by TransAlta and certain of its affiliates. At Sept. 30, 2024, TransAlta Renewables is a wholly-owned subsidiary and has no remaining non-controlling interest.

As at Sept. 30, 2024, the Company owned 50.01 per cent of TA Cogen (Sept. 30, 2023 – 50.01 per cent), which owns, operates or has an interest in three natural-gas-fired cogeneration facilities (Ottawa, Windsor and Fort Saskatchewan) and a natural-gas-fired facility (Sheerness). As at Sept. 30, 2024, the Company owned 83 per cent of Kent Hills Wind LP (prior to Oct. 5, 2023, financial information related to the 17 per cent non-controlling interest in Kent Hills Wind LP was included in the disclosures for TransAlta Renewables), which owns and operates three wind facilities.

Since we own 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 (loss) attributable to non-controlling interests for the three and nine months ended Sept. 30, 2024, decreased by $32 million and $82 million, respectively, compared to the same periods in 2023, primarily as a result of lower TA Cogen net earnings resulting from lower merchant pricing in the Alberta market and the acquisition of TransAlta Renewables on Oct. 5, 2023.

Cash Flows

Cash and cash equivalents for the nine months ended Sept. 30, 2024, decreased compared to the same period in 2023. On Oct. 5, 2023, the Company paid total consideration of $1.3 billion, comprising of $800 million cash and 46 million common shares valued at $514 million, for the acquisition of TransAlta Renewables as discussed above.

The following table highlights additional significant changes in the unaudited interim condensed consolidated statements of cash flows for the nine months ended Sept. 30, 2024 and Sept. 30, 2023:

9 months ended Sept. 30	2024	2023	Increase/ (decrease)
Cash and cash equivalents, beginning of period	**348**	1,134	(786)
Provided by (used in):			
Operating activities	**581**	1,154	(573)
Investing activities	**(198)**	(591)	393
Financing activities	**(335)**	(455)	120
Translation of foreign currency cash	**5**	(11)	16
Cash and cash equivalents, end of period	**401**	1,231	(830)

Cash Flow from Operating Activities

Cash from operating activities for the nine months ended Sept. 30, 2024, decreased compared with the same period in 2023, primarily due to the following:

	9 months ended Sept. 30
Cash flow from operating activities for the nine months ended Sept. 30, 2023	1,154
Lower gross margin: Lower revenues net of unrealized gains from risk management activities, partially offset by lower fuel and purchased power and carbon compliance costs.	(433)
Higher current income tax expense due to the full utilization of Canadian non-capital loss carryforwards in 2023 offset by lower earnings before income taxes in 2024.	(68)
Unfavourable change in non-cash operating working capital balances: Lower accounts payables and accrued liabilities and higher collateral provided as a result of market price volatility.	(48)
Other non-cash items	(24)
Cash flow from operating activities for the nine months ended Sept. 30, 2024	**581**

Cash Flow used in Investing Activities

Cash used in investing activities for the nine months ended Sept. 30, 2024, decreased compared with the same period in 2023, primarily due to the following:

	9 months ended Sept. 30
Cash flow used in investing activities for the nine months ended Sept. 30, 2023	(591)
Lower additions to PP&E: Additions in 2023 were mainly for the construction of the Garden Plain wind facility, the Northern Goldfields solar facilities and White Rock and Horizon Hill wind projects. Additions in 2024 included White Rock and Horizon Hill wind facilities.	441
Lower proceeds on sale of PP&E: In 2023, the Company closed the sale of equipment related to its Sundance Unit 5 energy transition assets.	(25)
Lower proceeds under the new Mount Keith 132kV lease receivable as compared to the Southern Cross Energy lease receivable.	(25)
Other	2
Cash flow used in investing activities for the nine months ended Sept. 30, 2024	**(198)**

Cash Flow used in Financing Activities

Cash used in financing activities for the nine months ended Sept. 30, 2024, decreased compared with the same period in 2023, primarily due to the following:

	9 months ended Sept. 30
Cash flow used in financing activities for the nine months ended Sept. 30, 2023	(455)
Lower borrowings under credit facilities.	(35)
Lower realized losses on financial instruments.	32
Lower distributions paid to non-controlling interests: Related to lower TA Cogen net earnings resulting from lower merchant pricing in the Alberta market and the cessation of distributions by TransAlta Renewables non-controlling interest. On Oct. 5, 2023, the Company acquired all of the outstanding common shares of TransAlta Renewables not already owned, directly or indirectly.	170
Higher repurchase of common shares under NCIB.	(41)
Other	(6)
Cash flow used in financing activities for the nine months ended Sept. 30, 2024	**(335)**

Other Consolidated Analysis

Commitments

The Company has not incurred any additional contractual commitments in the nine months ended Sept. 30, 2024, either directly or through its interests in joint operations and joint ventures. Refer to the commitments disclosed elsewhere in the unaudited interim condensed consolidated financial statements and those disclosed in the 2023 annual audited financial statements.

Natural Gas Transportation Contracts

The Company has natural gas transportation contracts, which include 15-year natural gas transportation agreements 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. The Company is currently utilizing 200 TJ per day on average, and up to 350 TJ per day during peak demand periods, and also remarkets a portion of the excess capacity. In addition, there is an eight-year natural gas transportation agreements for 75 TJ per day on a firm basis, related to the Sheerness facility, ending in 2030 to 2031.

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 36 of the 2023 audited annual consolidated financial statements. There were no material changes to the contingencies in the nine months ended Sept. 30, 2024.

Financial Instruments

Refer to Note 14 of the notes to the audited annual 2023 consolidated financial statements and Note 10 and 11 of our unaudited interim condensed consolidated financial statements as at and for the nine months ended Sept. 30, 2024, for details on Financial instruments.

We may enter into commodity transactions involving non-standard features for which market-observable data is not available. These transactions are defined under IFRS as Level III instruments. Level III instruments incorporate inputs that are not observable from the market and fair value is therefore determined using valuation techniques. Fair values are validated by using reasonably possible alternative assumptions as inputs to valuation techniques and any material differences are disclosed in the notes to the unaudited interim condensed consolidated financial statements.

At Sept. 30, 2024, Level III instruments had a net liability carrying value of $142 million (Dec. 31, 2023 – net liability $147 million). Our risk management profile and practices have not changed materially from Dec. 31, 2023.

Additional IFRS Measures and Non-IFRS Measures

An additional IFRS measure is a line item, heading or subtotal that is relevant to an understanding of the unaudited interim condensed consolidated financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the unaudited interim condensed consolidated financial statements but is not presented elsewhere in the unaudited interim condensed consolidated financial statements. We have included line items entitled gross margin and operating income (loss) in our unaudited interim condensed consolidated statements of earnings (loss) for the three and nine months ended Sept. 30, 2024 and 2023. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

We use a number of financial measures to evaluate our performance and the performance of our business segments, including measures and ratios that are presented on a non-IFRS basis, as described below. Unless otherwise indicated, all amounts are in Canadian dollars and have been derived from our unaudited interim condensed consolidated financial statements prepared in accordance with IFRS. We believe that these non-IFRS amounts, measures and ratios, read together with our IFRS amounts, provide readers with a better understanding of how management assesses results.

Non-IFRS amounts, measures and ratios do not have standardized meanings under IFRS. They are unlikely to be comparable to similar measures presented by other companies and should not be viewed in isolation from, as an alternative to, or more meaningful than, our IFRS results.

Non-IFRS Financial Measures

Adjusted EBITDA, FFO, FCF, total net debt, total consolidated net debt and adjusted net debt are non-IFRS measures that are presented in this MD&A. Refer to the Segmented Financial Performance and Operating Results, Selected Quarterly Information, Financial Capital and Key Non-IFRS Financial Ratios sections of this MD&A for additional information, including a reconciliation of such non-IFRS measures to the most comparable IFRS measure.

Adjusted EBITDA

Each business segment assumes responsibility for its operating results measured by adjusted EBITDA. Adjusted EBITDA is an important metric for management that represents our core operational results. In the second quarter of 2024, our reported EBITDA composition was adjusted to include the impact of acquisition transaction and integration costs as the Company does not have frequent business acquisitions and the acquisition transaction and integration costs are not reflective of Company's ongoing business performance. Accordingly, the Company has applied this composition to all previously reported periods. Interest, taxes, depreciation and amortization are not included, as differences in accounting treatments may distort our core business results. In addition, certain reclassifications and adjustments are made to better assess results, excluding those items that may not be reflective of ongoing business performance. This presentation may facilitate the readers' analysis of trends.

The following are descriptions of the adjustments made.

Adjustments to Revenue

- Certain assets that we own in Canada and in 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.
- Adjusted EBITDA is adjusted to exclude the impact of unrealized mark-to-market gains or losses and unrealized foreign exchange gains or losses on commodity transactions.
- Adjustments are made for gains and losses related to closed positions effectively settled by offsetting positions with exchanges that have been recorded in the period the positions are settled.

Adjustments to Fuel and Purchased Power

- On the commissioning of the South Hedland facility in July 2017, we prepaid approximately $74 million of electricity transmission and distribution costs. Interest income is recorded on the prepaid funds. We reclassify this interest income as a reduction in the transmission and distribution costs expensed each period to reflect the net cost to the business.

Adjustments to OM&A

- Acquisition transaction and integration costs, mainly comprised of legal and consultant fees, are not included as these do not reflect ongoing business performance.

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

- Asset impairment charges and reversals are not included as these are accounting adjustments that impact depreciation and amortization and do not reflect ongoing business performance.
- Any gains or losses on asset sales or foreign exchange gains or losses are not included as these are not part of operating income.

Adjustments for Equity-Accounted Investments

- During the fourth quarter of 2020, we acquired a 49 per cent interest in the Skookumchuck wind facility, which is treated as an equity investment under IFRS and our proportionate share of the net earnings is reflected as equity income on the statement of earnings under IFRS. As this investment is part of our regular power-generating operations, we have included our proportionate share of the adjusted EBITDA of the Skookumchuck wind facility in our total adjusted EBITDA. In addition, in the Wind and Solar adjusted results, we have included our proportionate share of revenues and expenses to reflect the full operational results of this investment. We have not included EMG International, LLC's adjusted EBITDA in our total adjusted EBITDA as it does not represent our regular power-generating operations.

Average Annual EBITDA

Average annual EBITDA is a forward-looking non-IFRS financial measure that is used to show the average annual EBITDA that the project currently under construction is expected to generate upon completion.

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.

Adjustments to Cash Flow from Operations

- FFO related to the Skookumchuck wind facility, which is treated as an equity-accounted investment under IFRS and equity income, net of distributions from joint ventures, is included in cash flow from operations under IFRS. As this investment is part of our regular power generating operations, we have included our proportionate share of FFO.
- Payments received on finance lease receivables are reclassified to reflect cash from operations.
- We adjust for items included in cash flow operations 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").
- Cash received/paid on closed positions are reflected in the period that the position is settled.
- Acquisition transaction and integration costs are reclassified to reflect cash from operations.
- Other adjustments include payments/receipts for production tax credits associated with tax equity financing, which are reductions to tax equity debt and include distributions from equity-accounted joint ventures.

Free Cash Flow ("FCF")

FCF is an important metric as it represents the amount of cash that is available to invest in growth initiatives, make scheduled principal repayments on debt, repay maturing debt, pay common share dividends or repurchase common shares. Changes in working capital are excluded so FFO and FCF are not distorted by changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and timing of receipts and payments. FCF is a non-IFRS measure.

Non-IFRS Ratios

FFO per share, FCF per share and adjusted net debt to adjusted EBITDA are non-IFRS ratios that are presented in the MD&A. Refer to the Reconciliation of Cash Flow from Operations to FFO and FCF and Key Non-IFRS Financial Ratios sections of this MD&A for additional information.

FFO per Share and FCF per Share

FFO per share and FCF per share are calculated using the weighted average number of common shares outstanding during the period. FFO per share and FCF per share are non-IFRS ratios.

Supplementary Financial Measures

Total sustaining capital expenditures and total growth and development expenditures are supplementary financial measures used to present our spend related to facilitate safe and reliable operation of our existing facilities and the construction of projects, respectively. Refer to the Capital Expenditures section of this MD&A for additional information.

The Alberta electricity portfolio metrics disclosed are supplementary financial measures used to present the gross margin by segment for the Alberta market. Refer to the Alberta Electricity Portfolio section of this MD&A for additional information.

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

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings before income taxes for the three months ended Sept. 30, 2024:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	105	2	314	165	55	—	641	(3)	—	638
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	1	74	(5)	(8)	(3)	—	59	—	(59)	—
Realized gain (loss) on closed exchange positions	—	—	(3)	—	12	—	9	—	(9)	—
Decrease in finance lease receivable	—	—	5	—	—	—	5	—	(5)	—
Finance lease income	—	1	2	—	—	—	3	—	(3)	—
Unrealized foreign exchange loss on commodity	—	—	1	—	—	—	1	—	(1)	—
Adjusted revenues	106	77	314	157	64	—	718	(3)	(77)	638
Fuel and purchased power	4	5	100	104	—	—	213	—	—	213
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	4	5	99	104	—	—	212	—	1	213
Carbon compliance	—	—	40	1	—	—	41	—	—	41
Gross margin	102	72	175	52	64	—	465	(3)	(78)	384
OM&A	13	26	43	17	10	35	144	(1)	—	143
Reclassifications and adjustments:										
Acquisition and integration costs	—	—	—	—	—	(1)	(1)	—	1	—
Adjusted OM&A	13	26	43	17	10	34	143	(1)	1	143
Taxes, other than income taxes	—	5	3	1	—	1	10	—	—	10
Net other operating income	—	(3)	(10)	—	—	—	(13)	—	—	(13)
Adjusted EBITDA[2]	89	44	139	34	54	(35)	325			
Equity loss										(1)
Finance lease income										3
Depreciation and amortization										(133)
Asset impairment charges										(20)
Interest income										4
Interest expense										(83)
Foreign exchange loss										(6)
Gain on sale of assets and other										1
Earnings before income taxes										9

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

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings before income taxes for the three months ended Sept. 30, 2023:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	163	62	522	188	86	—	1,021	(4)	—	1,017
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	4	(112)	5	(67)	—	(170)	—	170	—
Realized gain on closed exchange positions	—	—	4	—	8	—	12	—	(12)	—
Decrease in finance lease receivable	—	—	14	—	—	—	14	—	(14)	—
Finance lease income	—	—	2	—	—	—	2	—	(2)	—
Unrealized foreign exchange gain on commodity	—	—	—	—	(1)	—	(1)	—	1	—
Adjusted revenues	163	66	430	193	26	—	878	(4)	143	1,017
Fuel and purchased power	4	6	111	148	—	—	269	—	—	269
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	4	6	110	148	—	—	268	—	1	269
Carbon compliance	—	—	28	—	—	—	28	—	—	28
Gross margin	159	60	292	45	26	—	582	(4)	142	720
OM&A	9	20	45	15	13	30	132	(1)	—	131
Taxes, other than income taxes	—	4	3	1	—	—	8	—	—	8
Net other operating income	—	(1)	(10)	—	—	—	(11)	—	—	(11)
Adjusted EBITDA[2]	150	37	254	29	13	(30)	453			
Finance lease income										2
Depreciation and amortization										(140)
Asset impairment reversals										58
Interest income										16
Interest expense										(69)
Foreign exchange loss										(5)
Loss on sale of assets and other										(1)
Earnings before income taxes										453

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

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings before income taxes for the nine months ended Sept. 30, 2024:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	316	253	1,031	461	154	(34)	2,181	(14)	—	2,167
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(3)	61	(86)	(28)	(5)	—	(61)	—	61	—
Realized gain (loss) on closed exchange positions	—	—	8	—	(16)	—	(8)	—	8	—
Decrease in finance lease receivable	—	1	14	—	—	—	15	—	(15)	—
Finance lease income	—	4	5	—	—	—	9	—	(9)	—
Unrealized foreign exchange loss on commodity	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted revenues	313	319	971	433	133	(34)	2,135	(14)	46	2,167
Fuel and purchased power	13	22	339	316	—	—	690	—	—	690
Reclassifications and adjustments:										
Australian interest income	—	—	(3)	—	—	—	(3)	—	3	—
Adjusted fuel and purchased power	13	22	336	316	—	—	687	—	3	690
Carbon compliance	—	—	106	1	—	(34)	73	—	—	73
Gross margin	300	297	529	116	133	—	1,375	(14)	43	1,404
OM&A	39	70	131	50	29	105	424	(3)	—	421
Reclassifications and adjustments:										
Acquisition and integration costs	—	—	—	—	—	(8)	(8)	—	8	—
Adjusted OM&A	39	70	131	50	29	97	416	(3)	8	421
Taxes, other than income taxes	2	13	9	3	—	1	28	(1)	—	27
Net other operating income	—	(7)	(30)	—	—	—	(37)	—	—	(37)
Adjusted EBITDA[2]	259	221	419	63	104	(98)	968			
Equity income										3
Finance lease income										9
Depreciation and amortization										(388)
Asset impairment charges										(26)
Interest income										19
Interest expense										(232)
Foreign exchange loss										(12)
Gain on sale of assets and other										4
Earnings before income taxes										370

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings before income taxes for the nine months ended Sept. 30, 2023:

	Hydro	Wind & Solar[(1)]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[(1)]	Reclass adjustments	IFRS financials
Revenues	456	263	1,268	576	181	1	2,745	(14)	—	2,731
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(2)	(4)	(120)	(12)	42	—	(96)	—	96	—
Realized loss on closed exchange positions	—	—	(13)	—	(95)	—	(108)	—	108	—
Decrease in finance lease receivable	—	—	40	—	—	—	40	—	(40)	—
Finance lease income	—	—	10	—	—	—	10	—	(10)	—
Adjusted revenues	454	259	1,185	564	128	1	2,591	(14)	154	2,731
Fuel and purchased power	14	22	326	419	—	1	782	—	—	782
Reclassifications and adjustments:										
Australian interest income	—	—	(3)	—	—	—	(3)	—	3	—
Adjusted fuel and purchased power	14	22	323	419	—	1	779	—	3	782
Carbon compliance	—	—	85	—	—	—	85	—	—	85
Gross margin	440	237	777	145	128	—	1,727	(14)	151	1,864
OM&A	35	55	136	46	33	86	391	(2)	—	389
Taxes, other than income taxes	2	11	11	3	—	—	27	(1)	—	26
Net other operating income	—	(4)	(30)	—	—	—	(34)	—	—	(34)
Adjusted EBITDA[(2)]	403	175	660	96	95	(86)	1,343			
Equity income										1
Finance lease income										10
Depreciation and amortization										(489)
Asset impairment reversals										74
Interest income										47
Interest expense										(215)
Gain on sale of assets and other										4
Earnings before income taxes										915

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

(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

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 Sept. 30		9 months ended Sept. 30	
	2024	**2023**	**2024**	**2023**
Cash flow from operating activities[1]	**229**	681	**581**	1,154
Change in non-cash operating working capital balances	**(48)**	(355)	**59**	11
Cash flow from operations before changes in working capital	**181**	326	**640**	1,165
Adjustments				
Share of adjusted FFO from joint venture[1]	**—**	2	**4**	10
Decrease in finance lease receivable	**5**	14	**15**	40
Clean energy transition provisions and adjustments[2]	**—**	—	**—**	7
Realized gain (loss) on closed exchanged positions	**9**	12	**(8)**	(108)
Acquisition and integration costs	**1**	—	**8**	—
Other[3]	**4**	3	**14**	8
FFO[4]	**200**	357	**673**	1,122
Deduct:				
Sustaining capital[1]	**(35)**	(36)	**(75)**	(100)
Productivity capital	**—**	(1)	**—**	(2)
Dividends paid on preferred shares	**(13)**	(14)	**(39)**	(39)
Distributions paid to subsidiaries' non-controlling interests	**(10)**	(75)	**(34)**	(204)
Principal payments on lease liabilities	**(1)**	(3)	**(3)**	(8)
Other	**(1)**	—	**(1)**	—
FCF[4]	**140**	228	**521**	769
Weighted average number of common shares outstanding in the period	**296**	263	**303**	265
FFO per share[4]	**0.68**	1.36	**2.22**	4.23
FCF per share[4]	**0.47**	0.87	**1.72**	2.90

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

(2) 2023 includes amounts related to onerous contracts recognized in 2021.

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

(4) These items are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2024	**2023**	**2024**	**2023**
Adjusted EBITDA[(1)(4)]	**325**	453	**968**	1,343
Provisions	**2**	(4)	**8**	—
Net interest expense[(2)]	**(62)**	(40)	**(167)**	(123)
Current income tax expense	**(63)**	(37)	**(123)**	(55)
Realized foreign exchange gain (loss)	**1**	(7)	**(7)**	(13)
Decommissioning and restoration costs settled	**(10)**	(6)	**(29)**	(22)
Other non-cash items	**7**	(2)	**23**	(8)
FFO[(3)(4)]	**200**	357	**673**	1,122
Deduct:				
Sustaining capital[(4)]	**(35)**	(36)	**(75)**	(100)
Productivity capital	**—**	(1)	**—**	(2)
Dividends paid on preferred shares	**(13)**	(14)	**(39)**	(39)
Distributions paid to subsidiaries' non-controlling interests	**(10)**	(75)	**(34)**	(204)
Principal payments on lease liabilities	**(1)**	(3)	**(3)**	(8)
Other	**(1)**	—	**(1)**	—
FCF[(3)(4)]	**140**	228	**521**	769

(1) Adjusted EBITDA is defined in the Additional IFRS Measures and Non-IFRS Measures section of this MD&A and reconciled to earnings (loss) before income taxes above.

(2) Net interest expense includes interest expense for the period less interest income.

(3) These items are not defined and have no standardized meaning under IFRS. FFO and FCF are defined in the Additional IFRS Measures and Non-IFRS Measures section of this MD&A and reconciled to cash flow from operating activities above.

(4) Includes our share of amounts for the Skookumchuck wind facility, an equity-accounted joint venture. Refer to the Capital Expenditures section of this MD&A for details of sustaining capital expenditures.

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

As at	Sept. 30, 2024	Dec. 31, 2023
Period-end long-term debt(1)	**3,417**	3,466
Exchangeable debentures	**347**	344
Less: Cash and cash equivalents(2)	**(401)**	(345)
Add: 50 per cent of issued preferred shares and exchangeable preferred shares(3)	**671**	671
Other(4)	**(15)**	(12)
Adjusted net debt(5)	**4,019**	4,124
Adjusted EBITDA(6)	**1,257**	1,632
Adjusted net debt to adjusted EBITDA (times)	**3.2**	2.5

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

(2) Cash and cash equivalents, net of bank overdraft.

(3) Exchangeable preferred shares are considered equity with dividend payments for credit-rating purposes. For accounting purposes, they are accounted for as debt with interest expense in the unaudited interim condensed consolidated financial statements. For purposes of this ratio, we consider 50 per cent of issued preferred shares, including these, as debt.

(4) Includes principal portion of TransAlta OCP restricted cash ($17 million for the period ended Sept. 30, 2024 and for the year ended Dec. 31, 2023) and fair value of hedging instruments on debt (included in risk management assets and/or liabilities on the unaudited interim condensed consolidated statements of financial position).

(5) The tax equity financing for the Skookumchuck wind facility, an equity-accounted joint venture, is not represented in this amount. Adjusted net debt is not defined and has no standardized meaning under IFRS. Presenting this item from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(6) Last 12 months.

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 Sept. 30, 2024 was higher compared to Dec. 31, 2023, primarily due to lower adjusted EBITDA.

2024 Outlook

The following table outlines our expectations on key financial targets and related assumptions for 2024 and should be read in conjunction with the narrative discussion that follows and the Governance and Risk Management section of this MD&A. The Company is tracking towards the upper end of our guidance for 2024:

	2024 Target	2023 Actuals
Adjusted EBITDA(1)	$1,150 million - $1,300 million	$1,632 million
FCF(1)	$450 million - $600 million	$890 million
FCF per share	$1.47 - $1.96	$3.22
Dividend per share (annualized)	$0.24	$0.22

(1) These items are not defined and have no standardized meaning under IFRS. Refer to the Reconciliation of Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. See also the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The Company's outlook for 2024 may be impacted by a number of factors as detailed further below.

Range of key 2024 power and gas price assumptions

Market	Updated 2024 Assumptions	2024 Assumptions
Alberta spot ($/MWh)	$60 to $75	$75 to $95
Mid-C spot (US$/MWh)	US$60 to US$70	US$75 to US$85
AECO gas price ($/GJ)	$1.25 to $1.75	$2.50 to $3.00

Alberta spot price sensitivity: a +/- $1 per MWh change in spot price is expected to have a +/-$1 million impact on adjusted EBITDA for balance of year 2024.

Other assumptions relevant to the 2024 outlook

	Updated 2024 Expectations	2024 Expectations
Energy Marketing gross margin	$150 million to $170 million	$110 million to $130 million
Sustaining capital	no change	$130 million to $150 million
Corporate cash taxes	$140 million to $160 million	$95 million to $130 million
Cash interest	no change	$240 million to $260 million

Alberta Hedging

Range of hedging assumptions	Q4 2024	Full year 2025	Full year 2026
Hedged production (GWh)	2,415	5,541	3,640
Hedge price ($/MWh)	$82	$75	$78
Hedged gas volumes (GJ)	15 million	28 million	18 million
Hedge gas prices ($/GJ)	$2.55	$3.51	$3.67

Refer to the 2024 Outlook section in our 2023 Annual MD&A for further details relating to our Outlook and related assumptions.

Liquidity and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities. As at Sept. 30, 2024, we had access to $1.8 billion in liquidity, including $401 million in cash.

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. There were no material changes in estimates in the quarter.

Valuation of PP&E and Associated Contracts

An assessment is made at each reporting date as to whether there is any indication that an impairment loss may exist or that a previously recognized impairment loss may no longer exist or may have decreased. An impairment exists when the carrying amount of an asset exceeds its recoverable amount, which is the higher of its fair value less costs of disposal and its value in use. An impairment loss recognized in a prior period is reversed if there has been a change in the estimates used to determine the asset's recoverable amount.

During the three and nine months ended Sept. 30, 2024, there were no significant changes in estimates, however, significant estimation uncertainty and judgment is applied in determining the recoverable amount of the Wind and Solar segment, due to the sensitivity of the significant assumptions to the future cash flows and the effect that changes in these assumptions would have on the recoverable amount.

For the purposes of the 2024 goodwill impairment review, the Company determined the recoverable amounts of the Wind and Solar segment by calculating the fair value less costs of disposal using discounted cash flow projections. In 2024, the Company relied on the recoverable amounts determined in 2023 for the Hydro and Energy Marketing segments in performing the 2024 goodwill impairment review. The recoverable amounts are based on the Company's long-range forecasts for the periods extending to the last planned asset retirement in 2072. The resulting fair value measurements are categorized within Level III of the fair value hierarchy. No impairment of goodwill arose for any segment.

The significant assumptions impacting the determination of fair value for the Wind and Solar segment, with a high degree of subjectivity, are the following:

- Forecasts of sales prices for each facility are determined by taking into consideration contract prices for facilities subject to long- or short-term contracts, forward price curves for merchant plants and regional supply-demand balances. Where forward price curves are not available for the duration of the facility's useful life, prices are determined by extrapolation techniques using historical industry and company-specific data. Merchant electricity prices used in Wind and Solar models ranged between \$40 to \$225 per MWh during the forecast period (2023 – \$35 to \$238 per MWh).
- Discount rates used ranged from 6.4 to 7.3 per cent (2023 – 6.4 to 7.5 per cent).
- The White Rock wind and the Horizon Hill wind facilities are subject to location specific price basis, sourced from third party analysis. This analysis is based on models of the transmission system, including assumptions around potential system upgrades as well as forecasted generation and load in the area.

Refer to Note 2(P)(I) of the Company's 2023 audited annual consolidated financial statements for further details on significant accounting judgments and key sources of estimation uncertainty of impairment of property, plant and equipment and goodwill.

Accounting Changes

Current Accounting Changes

Amendments to IAS 1 Non-current Liabilities with Covenants and Classification of Liabilities as Current or Non-current

In October 2022, the IASB issued Non-current Liabilities with Covenants, which amends IAS 1 Presentation of Financial Statements, to clarify how conditions with which an entity must comply within 12 months after the reporting period affect the classification of a liability. In January 2020, the IASB issued Classification of Liabilities as Current or Non-current, which amends IAS 1 Presentation of Financial Statements regarding the classification of liabilities as current or non-current, clarifying that contractual rights and conditions existing at the end of the reporting period are relevant in determining whether the Company has a right to defer settlement of a liability by at least 12 months.

Additionally, the IASB clarified that the classification of a liability is unaffected by the likelihood that an entity will exercise its deferral right. The amendments are applied retrospectively, effective for annual periods beginning on or after Jan. 1, 2024, and were adopted by the Company on that date.

On Jan. 1, 2024, the Company reclassified the Exchangeable Securities from non-current liabilities to current liabilities as the conversion option can be exercised at any time after Jan. 1, 2025, although there is no obligation to deliver cash equivalent resources and the holder cannot call for repayment. This accounting is consistent with the amendment.

Future Accounting Changes

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.

On April 9, 2024, the IASB issued a new standard, IFRS 18 *Presentation and Disclosure in Financial Statements*, which introduced new requirements for improved comparability in the statement of profit or loss, enhanced transparency of management-defined performance measures and more useful grouping of information in the financial statements. The standard is effective for annual reporting periods beginning on or after Jan. 1, 2027. The Company is currently evaluating the impacts to the financial statements.

Governance and Risk Management

Our business activities expose us to a variety of risks and opportunities including, but not limited to, regulatory changes, rapidly changing market dynamics and increased volatility in our key commodity markets. Our goal is to manage these risks and opportunities so that we are in a position to develop our business and achieve our goals while remaining reasonably protected from an unacceptable level of risk or financial exposure. We use a multilevel 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 2023 Annual MD&A and Note 11 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, 2023.

Regulatory Updates

Refer to the Policy and Legal Risks discussion in our 2023 Annual MD&A for further details that supplement the recent developments as discussed below:

Canada

Federal

Canada's 2030 nationally determined contribution under the Paris Agreement was updated in 2021 with a revised target of 40 to 45 per cent below 2005 levels of greenhouse gas emissions. Canada's next nationally determined contribution will be the 2035 emissions reduction target. Under the *Canadian Net Zero Emissions Accountability Act*, the government must set an emissions reduction target for 2035 by Dec. 1, 2024.

In 2022, Environment and Climate Change Canada ("ECCC") released the proposed framework for the Clean Electricity Regulations ("CER") to achieve a net-zero electricity sector in Canada by 2035. The draft CER was published in Canada Gazette Part I ("CGI") on Aug. 19, 2023 for stakeholder review and comment until Nov. 2, 2023. The government expects to finalize the CER through Canada Gazette II ("CGII") in late 2024.

In response to the United States' Inflation Reduction Act ("IRA") signed into law in August 2022, the Government of Canada proposed multiple Investment Tax Credits ("ITCs") to incent investment in clean energy projects. As of June 2024, the Carbon Capture Utilization and Storage ("CCUS") ITC, the Clean Technology ITC, the Clean Technology Manufacturing ITC and the Clean Hydrogen ITC have all been passed into law. The CCUS and Clean Technology ITCs are now available to apply for and claim.

The Clean Technology Manufacturing ITC and the Clean Hydrogen ITC are not expected to be available for application and claim until Fall 2024.

The Government is targeting introduction of legislation on the Clean Electricity ITC in the fall of 2024, with additional details on an Electric Vehicle Supply Chain ITC expected also expected in the fall of 2024.

The Canadian Securities Administrators anticipate seeking comment on the revised *National Instrument 51-107 Disclosure of Climate-related Matters* after considering the

Canadian Sustainability Standards Board's climate-related disclosures standard, which is expected in 2025.

Alberta

On April 19, 2023, the Government of Alberta released the Emissions Reduction and Energy Development Plan, which outlines an aspiration to achieve a carbon-neutral economy by 2050. The plan frames Alberta's approach to enhance the province's position as a global leader in emissions reductions, clean technology and innovation, while maintaining Alberta's competitiveness from a sustainable resource development perspective. The plan is guided by eight strategic principles and outlines the actions, opportunities and new commitments that will reduce emissions and maintain energy security.

On Mar. 11, 2024, the Government filed two new interim regulations: the *Market Power Mitigation Regulation* and *Supply Cushion Regulation*. Both interim regulations became effective on July 1, 2024 and will expire on Nov. 30, 2027.

The *Market Power Mitigation Regulation* imposes an offer cap on the gas-fired generating units controlled by a large market participant (with offer control of 5 per cent of all generation). The offer cap would only restrict our offering price, not settlement price, and is triggered when the pool prices hit a threshold of two-months worth of net revenue for a hypothetical natural-fired combined cycle power plant. The offer cap is set at $125 per MWh or 25 times the day-ahead natural gas price and applies to the remainder of the calendar month in which the threshold was triggered. This regulation is not expected to have a significant impact on the Company given the weaker pricing conditions expected over the period of time that the regulation will be in place.

The *Supply Cushion Regulation* imposes specific requirements on the AESO to direct long-lead time generation (generators that require one hour or more to synchronize to the grid). The AESO is required to forecast and take action to direct long-lead time generation on line when the supply cushion is expected to be equal to or less than 932 MW. Long-lead time generation will receive a cost guarantee that will provide top ups to compensate a resource that is directed on by the AESO if the pool price revenues do not provide sufficient compensation to cover fuel and variable costs.

Also on March 11, 2024, the Government of Alberta announced its decision to pursue development of a Restructured Energy Market ("REM"). In July 2024, the Government of Alberta provided a high-level framework for the REM design which will include a day-ahead market, strategic bidding with market power mitigation, a review of the price floor and price ceiling, uniform market pricing, shorter settlement windows and economic dispatch.

The AESO issued design options papers in July and August 2024, providing background for each REM element and presenting various options for discussion in its first set of three week-long industry stakeholder working group sessions held from Sept. 1 to Oct. 4, 2024. These sessions were initial discussions that sought to create a general understanding of how the market design may change with the introduction of different REM elements. The AESO plans to complete a second set of working group discussions from Oct. 29 to Nov. 29 as well as broader industry consultation and written submissions through the fourth quarter of 2024 and the first quarter of 2025. The AESO plans to file new market rules to implement the detailed design with the AUC in the first or second quarter of 2025 and receive approval by the fourth quarter of 2025 or the first quarter of 2026.

On July 11, 2024, the Government also announced future changes to the Transmission Regulation. The Government plans to move away from the congestion-free planning standard and adopt an "optimal" planning approach, where transmission expansion and upgrade decisions will be based on cost and benefit studies. The Government also plans to allocate transmission system and ancillary services costs based on cost causation. The Government is consulting on the changes in fall 2024 and plans to propose the legislative amendment in spring 2025.

On Feb. 28, 2024, the Government of Alberta announced new restrictions on new renewable projects that includes prohibiting wind generation development within 35 kilometres of a protected area or other area designated a "pristine viewscape" by the Government, restricting renewable developments on class 1 and 2 agricultural lands, imposing new mandatory requirements to post bonds and/or provide financial security to meet reclamation obligations. Since that announcement, the Department of Environment and Protected Areas initiated stakeholder consultation on mandatory reclamation obligations in the third quarter of 2024. The new reclamation obligations and financial security requirements will be imposed on projects approved on or after March 1, 2024, and will not apply to existing facilities. The impacts to TransAlta's facilities are limited to future development projects.

United States

On March 6, 2024, the U.S. Securities and Exchange Commission ("SEC") adopted final rules for climate-related disclosures. On April 4, 2024, SEC paused the implementation of these rules as it awaits a court review of the new rules following a series of legal challenges by several states and business groups. The Company is exempt from these rules because TransAlta is a multi jurisdictional disclosure system issuer filing on Form 40-F.

On Aug. 31, 2024, the State of California passed the *Climate-Related Financial Risk Act (Senate Bill 261)*, which requires businesses with annual revenues over US$500 million operating in California to biannually disclose climate-related financial risks and their mitigation strategies to the public. The Bill may introduce reporting obligations to TransAlta commencing Jan. 1, 2026.

On May 9, 2024, the US Environmental Protection Agency published a final rule requiring existing fossil fuel-fired steam generating units and new fossil-fuel fired combustion turbines to reduce GHG emissions. Existing combustion turbines were deferred to a future time that was not defined. The rule is facing significant legal challenges from industry trade associations, labour and businesses. Despite these legal challenges, a federal appeals court is allowing the rule to remain in place as legal challenges proceed. There is no direct implication to TransAlta at this time.

Australia

Since the Labour Party formed government on May 21, 2022, Australia has increased its Nationally Determined Contribution commitment to increase the country's 2030 emissions reduction goal to 43 per cent below 2005 levels and confirmed its intent to boost renewable electricity production to 82 per cent of the electricity supply by 2030.

The "Future Made in Australia" budget released on May 14, 2024, highlighted the country's vision and commitment to become a renewable energy superpower in order to support the decarbonization of refining, mining and critical mineral processing. The budget plans to invest $22.7 billion over the next decade to maximize economic and industrial benefits of the move to net zero.

On Sept. 9, 2024, the Australian House of Representatives confirmed and passed the Senate amendments to the *Treasury Laws Amendment (Financial Market Infrastructure and Other Measures) Bill 2024*. The Bill received Royal Assent on Sept. 17, 2024 and will introduce reporting obligations in accordance with the *Australian Sustainability Reporting Standards - Disclosure of Climate-related Financial Information* to be finalized by the Australian Accounting Standards Board in the fourth quarter of 2024. Mandatory reporting will commence for fiscal year 2025.

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 nine months ended Sept. 30, 2024, the majority of our workforce supporting and executing our ICFR and DC&P continue to work on a hybrid basis. The Company has implemented appropriate controls and oversight for both in-office and remote work. There has been minimal impact to the design and performance of our internal controls.

ICFR is a framework designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the unaudited interim condensed 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) in order 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.

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 Sept. 30, 2024, the end of the period covered by this MD&A, our ICFR and DC&P were effective.

Glossary of Key Terms

Adjusted Availability

Availability is adjusted when economic conditions exist, such that planned routine and major maintenance activities are scheduled to minimize expenditures. In high price environments, actual outage schedules would change to accelerate the generating unit's return to service.

Alberta Electric System Operator (AESO)

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

Alberta Hydro Assets

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

Alberta Thermal

The segment includes the legacy and converted generating units at our Sundance and Keephills sites and includes the Highvale Mine.

Ancillary Services

As defined by the *Electric Utilities Act*, Ancillary Services are those services required to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency.

Automatic Share Purchase Plan (ASPP)

The ASPP is intended to facilitate repurchases of common shares under the NCIB, including at times when the Company would ordinarily not be permitted to make purchases due to regulatory restrictions or self-imposed blackout periods.

Availability

A measure of time, expressed as a percentage of continuous operation 24 hours a day, 365 days a year, that a generating unit is capable of generating electricity, regardless of whether or not it is actually generating electricity.

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.

Derate

To lower the rated electrical capability of a power generating facility or unit.

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

During periods of low market prices, the Company may choose not to generate power from the thermal fleet and will monetize its hedged or contract positions.

Economic Dispatch

Purchasing power to fulfil contractual obligations, when economical.

Exchangeable Debentures

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

Exchangeable Preferred Shares

On Oct. 30, 2020, Brookfield invested $400 million in the Company in exchange for redeemable, retractable first preferred shares (Series I). The Series I Preferred Shares are accounted for as current debt and the exchangeable preferred share dividends are reported as interest expense.

Exchangeable Securities

On March 22, 2019, the Company entered into an Investment Agreement whereby Brookfield Renewable Partners or its affiliates (collectively "Brookfield") agreed to invest $750 million in TransAlta through the purchase of exchangeable securities, which are exchangeable into an equity ownership interest in TransAlta's Alberta hydro assets in the future at a value based on a multiple of the Alberta hydro assets' future-adjusted EBITDA ("Option to Exchange").

Force Majeure

Literally means "greater force." These clauses excuse a party from liability if some unforeseen event beyond the control of that party prevents it from performing its obligations under the contract.

Free Cash Flow (FCF)

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. Amount is calculated as cash generated by the Company through its operations (cash from operations) minus the funds used by the Company for the purchase improvement, or maintenance of the long-term assets to improve the efficiency or capacity of the Company (capital expenditures).

Funds from Operations (FFO)

Represents a proxy for cash generated from operating activities before changes in working capital and provides the ability to evaluate cash flow trends in comparison with results from prior periods. Amount 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.

ICFR

Internal control over financial reporting.

IFRS

International Financial Reporting Standards.

ITC

The investment tax credit ("ITC") is a federal income tax credit for investments in certain types of qualifying clean electricity projects.

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

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.

TA Cogen

The Company owns 50.01 per cent in TransAlta Cogeneration, L.P. ("TA Cogen"), which owns, operates or has an interest in a portfolio of cogeneration facilities, including three natural-gas-fired cogeneration facilities (Ottawa, Windsor and Fort Saskatchewan) and a natural-gas-fired facility (Sheerness).

Term Facility

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

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.